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Windspear Business Reference Room
University of Alberta
118 Business Building
Edmonton, Alberta T6G 2G8

1997 Annual Report BC Gas Inc.

SHAPING OUR Future

CORPORATE Profile

BC Gas Inc. is a leading provider of energy and utility services in British Columbia. The Company owns two regulated operating entities. BC Gas Utility Ltd. is the largest distributor of natural gas in British Columbia, serving 732,000 residential, commercial and industrial customers in more than 100 communities. Trans Mountain Pipe Line Company Ltd. owns and operates the only pipeline transporting crude oil and refined petroleum products from Alberta to British Columbia and Washington State. Trans Mountain also owns and operates a pipeline system for transporting jet fuel to the Vancouver International Airport and a marine terminal for exporting crude oil and importing jet fuel via the Port of Vancouver. Through Inland Pacific Enterprises, BC Gas Inc. owns a number of non-regulated related businesses involved in energy and utility services.

Shares of BC Gas Inc. are traded on the Toronto, Montreal and Vancouver stock exchanges under the symbol BCG. The Company's head office is in Vancouver, British Columbia.

On the Cover



The business environment for utilities and energy services providers across North America is undergoing profound change, driven by new technology, less restrictive forms of regulation and greater competition. At BC Gas we are embracing the challenges and opportunities of this evolving environment to forge our own future.

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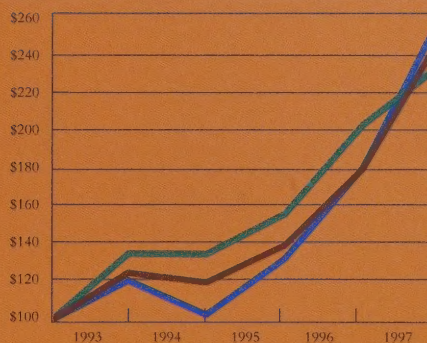
FINANCIAL Highlights

Years ended December 31	1997	1996	1995
<i>(Dollar amounts in millions except per share data)</i>			
Gross revenues	\$ 933.9	\$ 901.4	\$ 894.9
Net earnings before non-recurring items	\$ 65.2	\$ 61.6	\$ 48.2
Net earnings	\$ 50.8	\$ 105.6	\$ 47.5
Total assets	\$ 2,388.1	\$ 2,427.1	\$ 2,367.3
Earnings per share before non-recurring items	\$ 1.63	\$ 1.48	\$ 1.18
Earnings per share	\$ 1.27	\$ 2.53	\$ 1.16
Dividends per share	\$ 0.975	\$ 0.90	\$ 0.90
Book value per share	\$ 15.05	\$ 15.28	\$ 13.70
Return on equity	10.7%	10.3%	8.6%

Shareholder Return

With reinvested dividends, the total return for BC Gas shareholders in 1997 was 42 per cent. This compares with 15 per cent for the TSE 300 and 37 per cent for the gas and electric utilities index on The Toronto Stock Exchange.

— BC Gas
— TSE 300
— Gas and Electric Utilities



Return on an investment of \$100 assuming reinvestment of dividends



The multi-year incentive regulatory arrangements in place at both BC Gas Utility and Trans Mountain Pipe Line provide a framework for building value for customers and shareholders. In 1997 the British Columbia Utilities Commission approved a three-year incentive agreement relating to BC Gas Utility's revenue requirements for 1998 through 2000. BC Gas Utility's incentive structure is now one of the most progressive of its kind in place in the natural gas distribution industry in Canada.

LETTER TO Shareholders

■ In 1997, the pressures for change in the energy services industry continued to grow. Your Company is responding aggressively to these challenges, and is readying itself for the more competitive environment in which it will operate in the future. Before focusing further on the outlook for the Company, it is worthwhile to review the significant events and initiatives of the past year.

In April the Company announced its intention to increase the size of the share repurchase program to 4.1 million shares. Since August 1996, the Company has repurchased 3.1 million shares, representing 6.6 per cent of shares outstanding. The ongoing share buyback program optimizes our cost of capital while maintaining a strong financial base to take advantage of growth opportunities.

Unfortunately, the month of April also brought a tragedy when the worst natural gas explosion in the history of the

industry in British Columbia killed six people and injured 20 in Quesnel. Our employees acted promptly and with great sensitivity to the circumstances, and in the following months the Company has worked with various agencies to determine the cause of the explosion. A Coroner's inquest held in November determined that the explosion was accidental.

In May your directors raised the quarterly dividend on common shares 11 per cent, from 22.5 cents to 25 cents, to reflect higher ongoing earnings for the Company.

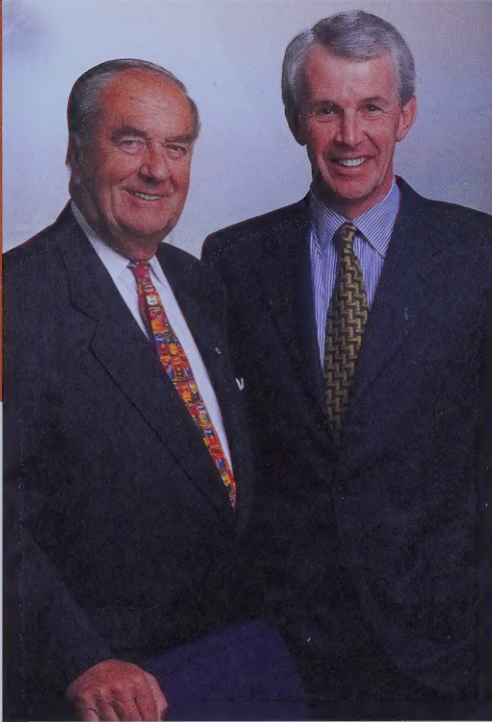
In July we were pleased to announce that we had succeeded in negotiating a settlement between the gas utility and its customers for a three-year incentive based rate regime beginning in 1998 wherein customers and the Company will share in the gains from productivity improvements. Our wholly owned subsidiary Trans Mountain Pipe Line Company Ltd., which is federally regulated, entered into an incentive based agreement in 1996.

Such agreements strike a balance of benefits between customers and shareholders with significant potential for both. We look forward to reporting the effect of these incentives on utility returns in future years.

In August the Board was surprised to receive the resignation of our President and Chief Executive Officer, Stephen T. Bellringer, who announced that he was leaving to head up a sports and entertainment company effective September 15. Your Company operated under the leadership of three chief executives in the course of 1997:

Following Steve's departure, Ronald L. Cliff assumed the role of President and CEO in addition to his responsibilities as Board Chairman. In November, following an extensive internal and external search, the Board was pleased to announce the appointment of John M. Reid as President and CEO. John previously served the Company as Executive Vice President, Finance and Chief Financial Officer, a position he had held since May 1995. Prior to joining BC Gas, John had been CEO of Scott Paper Ltd.

October saw the opening of the British Columbia Utilities Commission (BCUC) hearing into your Company's application to loop or twin its existing pipeline in the southern interior of BC. This potential \$350 million investment, known as the Southern Crossing Pipeline Project, developed out of the Company's integrated resource planning process conducted under the auspices of the BCUC. Few could have anticipated the attention and competitive clamour this looping project created in the regulatory process. The fact that this application drew alternative proposals from two other companies to expand their pipeline systems, three other companies proposing to build Liquefied Natural Gas (LNG) plants and one company proposing to construct an entire new pipeline from near the Alberta border to Vancouver is reflective of the new competitive reality of energy services in North America. We expect to receive a decision from the BCUC on our application sometime in March.



Ronald L. Cliff, Chairman (left)
John M. Reid, President and Chief
Executive Officer

The autumn months saw an acceleration of the gas utility's restructuring and refocusing initiated in 1996. New processes were introduced utilizing technology to reduce bureaucracy. We announced a strategy to exit the retailing of appliances out of our offices in the BC interior. What made sense years ago when no one else was selling natural gas appliances is not appropriate today when customers are well served by local retail merchants.

Similarly, the gas utility will discontinue accepting bill payments at our offices. Ninety per cent of customers currently use other bill payment options and the cost of the over-the-counter process has become too high, particularly in a time when other utilities have discontinued the practice.

The Company will continue to increase its focus on customer value. We will implement systems and practices that provide customers with the most reliable, safe, prompt and low cost products and services that the Company can profitably deliver in a competitive marketplace.

Financial Performance

The Company's 1997 earnings per share before non-recurring items amounted to \$1.63, up from \$1.48 in 1996. The increase before non-recurring items results from a combination of improved earnings—\$65.2 million, up from \$61.6 million in 1996—and a reduction in the average number of shares outstanding as a result of the Company's continuing share repurchase program.

After accounting for non-recurring gains and losses, 1997 net earnings were \$50.8 million or \$1.27 per share compared to \$105.6 million or \$2.53 per share in 1996. Net earnings in 1997 included non-recurring losses of \$0.36 per share arising from costs incurred in anticipation of the disposition of the Company's interest in the Williams Lake power plant and the restructuring program in the gas utility. In 1996 net earnings included a non-recurring gain of \$1.05 per share arising primarily from the Company's sale of its investment in Inland Gas & Oil Ltd.

Earnings for the gas utility in 1997 were \$3.3 million higher than in 1996. This was due primarily to customer

Net Earnings (Loss)

(in millions of dollars except per share amounts)

Years ended December 31	1997		1996	
	Total \$	Per Share	Total \$	Per Share
Gas utility operations	\$ 50.2	\$ 1.25	\$ 46.9	\$ 1.13
Oil pipeline operations	20.4	0.51	20.5	0.49
Related businesses	(1.3)	(0.03)	1.3	0.03
Corporate (BC Gas Inc.)	(4.1)	(0.10)	(7.1)	(0.17)
Earnings before non-recurring items	65.2	1.63	61.6	1.48
Non-recurring items	(14.4)	(0.36)	44.0	1.05
Net earnings	\$ 50.8	\$ 1.27	\$ 105.6	\$ 2.53

additions, increased margin from industrial customers and revenues from the gas supply incentive mechanism, offset by a decrease in the authorized rate of return on common equity to 10.25 per cent in 1997 from 11.0 per cent in 1996.

Oil pipeline earnings in 1997 were in line with 1996. The margin impact of lower transportation volumes was offset by reduced interest costs as a result of both lower interest rates and lower debt levels.

Earnings from related businesses engaged in energy and utility services activities were \$2.6 million lower in 1997 than in 1996. This was due primarily to the sale of Inland Gas & Oil Ltd. in August 1996.

The performance of the holding company, BC Gas Inc., was \$3 million (\$0.07 per share) better in 1997 than in 1996, the result of reduced debt levels due to the sale of Inland Gas & Oil Ltd., net of borrowings for the Company's share repurchase program.

Our healthy financial performance was recognized in the market for our shares. 1997 represented the best ever total return to shareholders as measured by combining the share appreciation and the dividends paid during the year and marked the third consecutive year that we have outperformed both the TSE 300 Index and the TSE Gas and Electric Utilities Index.

Related Businesses and Other Opportunities

In 1997 we made substantial progress in establishing a foundation for market oriented energy and utility services outside of a regulated environment. A highlight was the introduction of two programs under our new *Homeworks*® marketing brand. This initiative is aimed at developing long-term customer relationships for specialized, high-quality home services.

Distributed Energy Services Company, a new business venture to provide customized energy solutions and market our pipeline development expertise, was also launched in 1997. We expect DESCO to fill a need for utility services in remote communities and municipalities.

Inland Pacific Waterworks, in conjunction with an outside partner, is completing the development of a water treatment facility for the City of Dartmouth, Nova Scotia. This division is actively pursuing other municipal development projects. Our international consulting arm continues to provide design and project management services for clients in eastern Europe, Asia and Latin America.

In addition to producing earnings, our international involvement provides valuable insights and expertise for BC Gas personnel. Our energy marketing arm is continuing to pursue opportunities to expand market share in the British Columbia market through increased sales of natural gas and electricity to industrial customers. The U.S. energy marketing operation was sold in 1997.

Acknowledgments

Charles Armstrong will retire from the board of directors at the annual meeting in April. We have appreciated his advice and counsel during his time on the board and we wish him well in his retirement.

Shareholders have had a very successful year in 1997. This is due in no small part to the exemplary efforts of employees in all divisions and at all levels. The restructuring and change of 1997 created additional stresses for employees leaving the Company as well as those staying. Financial and counselling support packages were offered by the Company to assist employees through their transitions. As we reflect on their efforts we offer to all employees our profound thanks.

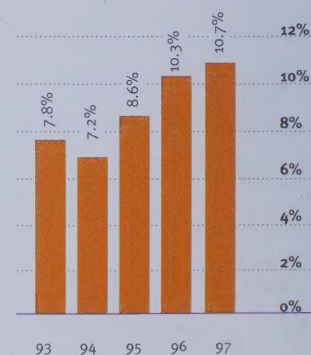
Shaping Our Future

Competition has arrived in our business. The intense competitive activity surrounding our Southern Crossing application was noted earlier. In the autumn, a subsidiary of a large Ontario-based distribution utility opened a gas appliance store in Greater Vancouver – the first of a chain it intends to operate in our service territory. At the same time, energy service companies are actively marketing products and services to commercial and industrial customers.

Our future does not look like our past. We must shape our future in light of new competitive challenges and new opportunities open to us in a marketplace where the bundled-service, integrated utility will no longer exist.

We are currently engaged in an intense examination of our business segments. In a competitive environment, we require a thorough understanding of

**BC Gas Inc.
Return On Equity**



Over the next three years, BC Gas plans to increase return on common equity to 12 per cent.

our products and services and who the key customers are for each. We need to focus on the value proposition of each that will give us a sustainable competitive advantage.

These business segments will be organized around a coalescing vision of our future. The themes underpinning this vision are:

- Value – value for the customer creates value for employees and shareholders;
- Productivity – first to cut costs, then to leverage revenue growth off a competitive base;
- Balanced Scorecard – safety and quality will not be compromised by cost reductions;
- Autonomy and Accountability – ownership of operating plans will be pushed out to those closer to the customer while maintaining a corporate screen for consistency with the corporate vision;
- Resource Allocation – how resources are allocated or reinvested is the key underpinning of long-term business success. Scarce resources will be allocated to areas of highest value.

We are determined to shift our culture to one that is customer focused. In a competitive environment price drives cost unlike the regulated monopoly environment where cost drives price. As we proceed we expect that further development of the corporate organization and process structures will be required to support the emerging strategies.

We intend to achieve these long-term repositioning goals while at the same time continuing to generate short-term earnings growth and attractive shareholder returns.



Ronald L. Cliff
Chairman



John M. Reid
President and Chief Executive Officer

March 3, 1998



In late 1997 BC Gas Utility embarked on a corporate restructuring to substantially increase productivity while continuing to provide customers with a safe, reliable product at a competitive price. Unlike a regulated monopoly where cost drives price, in a free market environment price drives cost. At BC Gas, our goal is to reduce costs, then to leverage revenue growth off a competitive base. The benefits from improved productivity will be shared between customers and shareholders.

SHAPING OUR Future

■ Growth for utility companies was once as simple as adding capital to meet customer demands and including the costs and allowed returns in customer rates. Services were integrated and their costs were dispersed across large numbers of customers.

Utilities provide a number of discrete products and services which do not have to be delivered by a single company. Technology and other developments have enabled many organizations to compete for different segments of the utility's value chain.

Customers, realizing they have choices, are demanding that utilities become competitive, lower their cost structures and improve service. Stakeholders of BC Gas Utility and Trans Mountain Pipe Line Company recognize the need for transition periods and have entered into multi-year regulatory arrangements designed around incentives to provide long-term value for both customers and shareholders.

BC GAS UTILITY

BC Gas Utility has moved quickly in this incentive period to reshape products, services and processes. Changes have been implemented to reduce operating costs, streamline customer service delivery systems, and to restructure work processes aimed at maintaining or increasing safety and reliability of service throughout the Company's operations.

In Greater Vancouver, dispatch operations have been combined to improve efficiency, a user fee has been introduced for non-emergency appliance calls and construction planning has been streamlined to provide new customers with a more efficient connection process, including greater continuity in their service contacts with the Company. Customers will be exposed to less bureaucracy and costs of service will be applied to those who ask for service rather than to all customers.

In the interior of the province the Company has stopped selling appliances out of its business offices, a practice begun when many communities did not have easy access to merchants offering natural gas appliances. Bill payments will not be accepted in branch offices; 90 per cent of customers currently use other bill payment options and the over-the-counter method is too costly to maintain for the small minority who use it. Branch offices will be converted to operations centres and a centralized call centre will allow the Company to provide more hours of customer service each day at a lower cost.

The Company is continuing to reduce capital requirements associated with adding new customers. A new mains extension test has been adopted to more rigorously examine the economics of extending natural gas to new areas. In addition a number of construction cost efficiencies associated with connecting new customers have been introduced. To improve efficiency in gas metering, the Company's internal meter exchange program has been revamped.

Responsible environmental management is central to the operating philosophy of BC Gas. The Company is committed to reducing methane and other greenhouse gases associated with its operations and during the year submitted a Greenhouse Gas Action Plan to the federal government's Voluntary Challenge and Registry Program. Over a five-year period, environmental audits are being conducted at all BC Gas Utility facilities. Ten facilities were audited in 1997 and action plans have been substantially completed for 11 of the 21 audits conducted to date. In 1998 BC Gas plans to finalize an evaluation of the Company's environmental management system with the completion of an ISO 14001 gap analysis.

Gas Supply

Financial hedging measures during a period of unprecedented high natural gas prices reduced price exposure for customers in the winter of 1996/97 by \$50 million. The Company continues to develop strategies and initiatives to protect customers from price fluctuations while minimizing overall natural gas supply costs.

1997 was the second year of an off-system incentive plan in which both customers and shareholders benefited from improved utilization and cost mitigation of natural gas supply resources (natural gas and associated transportation and storage capacity) contracted by the Company on behalf of customers. Total benefits from these activities for the contract year ended October 31, 1997 exceeded \$30 million with approximately \$25 million of this amount contributing to lower rates for customers.



In 1997 BC Gas Utility filed an application with the BCUC to build the Southern Crossing Pipeline which would parallel the Company's existing pipeline across southern BC. Through extensive consultation, this project has received the broad-based support of the many stakeholder groups along its routing. Southern Crossing is expected to save approximately \$30 million per year in natural gas supply costs compared to existing supply sources while providing greater security and diversity of supply for customers. The project would result in 3,000 person years of direct investment and employment within British Columbia. A decision on the application is expected in March 1998.

Business Development

While natural gas has been the fuel of choice for single-family dwelling units for many years, developers of multi-family and high-rise "vertical subdivisions" have traditionally been electricity customers—primarily because of the lower front-end cost. BC Gas Utility has introduced ways of metering individual suites and is now achieving success in working with developers

who are seeing the marketing advantage of units where potential buyers can enjoy the benefits of natural gas ranges and fireplaces. The condominium market should play a much larger role in the Company's future than it has in the past.

The Company is working at developing closer ties with a number of BC Aboriginal groups to extend natural gas service for expanded residential use and for business development projects. While there is uncertainty in the province over land claims, there is a large potential for development on lands that are clearly in native jurisdiction.

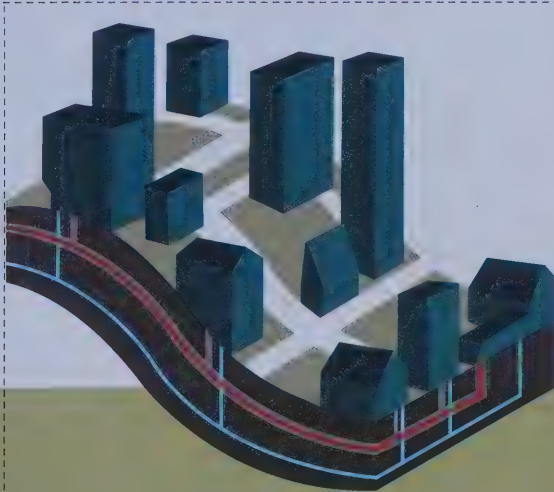
To keep capital requirements down while meeting increased demands, the Company is applying a multi-layered approach to system reinforcement: looping pipe, installing satellite LNG facilities and applying focused demand management programs are all examined as options, particularly in high growth areas affected by distribution system constraints.

Natural gas service is an attractive marketing feature for new homes. Besides ranking as one of the most economical methods for residential heating, natural gas provides efficient cooking energy and a clean and modern fireplace fuel.



A new organization-wide information system will improve our ability to see relevant data more clearly and to track and manage the competitive position of our products and services. When completed, the new system will provide profitability information related to customers and products, helping us to identify new product opportunities, expand market share and optimize value.

As the Company moves toward a more competitive environment, employees will require better information about how we provide value to our customers; and they will need it in a timely fashion to make them better equipped to meet competition head on. In 1998 the Company will implement a new business information system to meet that need. It will provide significantly better insights into our value propositions than we have had to date and it will do so with substantially leaner processes and lower costs.



The development of a geographical information system, planned for implementation over the next three years, will increase accuracy of the Company's gas facility information and reduce the number of incidents of third party damage to underground lines.

RELATED BUSINESSES

Homeworks®

In 1997 BC Gas launched two programs under its new Homeworks® brand, marketed outside the utility framework. Homeworks® builds on the Company's reputation for consumer trust, reliability, safety and comfort and aims to develop long-term customer relationships for specialized high-quality home comfort services. A province-wide distribution network offers opportunities for ongoing contact and collaboration with customers without the cost of maintaining retail operations.

Through an energy-based renovation program, residential customers can improve home energy efficiency based on a thorough proprietary diagnostic audit. Offered in conjunction with



an energy technology firm, actual renovation work is conducted through trained contractors. The program is unique in that it provides quality assurance for each completed project and promotes ongoing customer contact by allowing homeowners to phase renovations over time. The second *Homeworks*® program launched during the year provides customers with point-of-sale financing for energy and comfort-related products and services through a strategic alliance with a national bank. This program is available through 220 *Homeworks*® dealers.

Homeworks® is concentrating on increasing brand awareness and expanding its customer base and geographic scope, with the intent of providing residential customers with an integrated package of services to improve their home comfort experience.

Distributed Energy Services Company (DESCO)

DESCO was formed in 1997 to provide a range of utility services outside of a regulated utility framework. The new division offers a turnkey approach to supplying LNG (liquefied natural gas) to customers where natural gas service through the extension of the gas system is not economically viable. The commencement of LNG service to DESCO's first industrial customer in 1997 significantly reduced costs for the customer. DESCO operates a propane gas distribution system at Sun Peaks Ski Resort near Kamloops and is exploring opportunities to provide water and sewer services at the resort. DESCO is negotiating similar services as well as utility construction work for other communities and resorts.



The application of new technology at BC Gas will contribute to improved customer service, a reduction in paper flow and greater efficiencies throughout the Company. An area where technology will make a major difference is automated meter reading which reduces the cost and time associated with manual reading and enables better forecasting of commodity use. BC Gas is an industry leader in automated meter reading (AMR) and in 1998 will select the preferred communication technology for its AMR platform. The Company is also participating in a number of pilot projects with other utilities to simultaneously monitor consumption of electricity, water and natural gas.



TRANS MOUNTAIN PIPE LINE

In 1997, Trans Mountain Pipe Line benefited from higher than anticipated delivery volumes and efficiencies achieved under the incentive toll arrangement. While deliveries were below the strong levels achieved in 1996, they were up three per cent from 1995. Mainline deliveries of crude oil and refined products averaged 36,523 cubic metres per day in 1997.

Increased production of heavy oil during the fourth quarter created capacity constraints on pipelines eastbound from Edmonton. As a result, Trans Mountain moved higher volumes of light crude oil to Washington State and California markets and shipped heavy oil to California refineries via the Company's Westridge marine terminal. Westridge is the only marine terminal in western Canada for export of crude oil.

Trans Mountain is considering several expansion alternatives, including a mainline expansion in 1998 and a

Trans Mountain operates the only pipeline system transporting crude oil and petroleum products from Alberta and northeastern British Columbia to the west coast. Capacity constraints on east-bound pipelines from Alberta and the price of competing Alaska crude oil are two key factors affecting delivery volumes on the Company's system. Trans Mountain continues to benefit from increased demand on the U.S. west coast to replace declining production of offshore California heavy oil and Alaska North Slope crude oil.

future major system expansion to provide capacity for long-term growth in hydrocarbon shipments, particularly heavy oil, to west coast markets.

The delivery capacity of the Company's jet fuel pipeline system was increased during the year with the addition of a new pumping station at Burnaby terminal. This will enable the system to meet increasing demand for jet turbine fuel at Vancouver International Airport.



Trans Mountain Pipe Line System

Operational efficiencies and high delivery volumes during the fourth quarter enabled Trans Mountain to meet certain incentive criteria set by the toll agreement governing operation of the Company's Canadian mainline system. The five-year agreement allows shippers to share in net income above a specified threshold level. The total share of pre-tax revenues credited to shippers under these terms for 1997 was \$1.9 million.

Trans Mountain considers pipeline integrity, strong safety performance and environmental protection to be critical to the sound operation of its pipeline system. A number of programs are in place to ensure the Company is an industry leader in these important areas. For example, its pipeline integrity program includes hydrostatic testing to ensure the soundness and safety of the system. Two sections totalling 82 km were successfully retested in 1997 and the ongoing program calls for progressively testing the entire system over the next 10 to 12 years.

Because of growing U.S. demand and increasing population in the Vancouver area, the Company anticipates long-term growth in volumes of crude oil and refined products shipped through its pipeline system. Trans Mountain will expand system capacity on a timely basis to meet this growing demand. The Company is also pursuing opportunities for growth in hydrocarbon transportation and terminalling outside its current operating area.

Glossary

BRITISH COLUMBIA UTILITIES COMMISSION

A provincially appointed body that regulates the potential earnings, business operations and practices of several BC utilities.

Btu

British thermal unit. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

CORE MARKET

Generally refers to non-industrial and non-utility purchasers of natural gas and includes residential, commercial and institutional (i.e.: hospitals, universities) purchasers of natural gas.

DEMAND CHARGE

The portion of the cost of transportation that is payable on the full contracted capacity regardless of whether or not the space is used.

DEMAND SIDE MANAGEMENT (DSM)

Utility programs designed to influence the customer's energy consumption. Such programs include reducing gas consumption through efficiency and conservation, load shaping programs to reduce peak load and/or increase off peak load, and programs to encourage fuel substitution.

FIXED PRICE CONTRACTS

Contractual requirements for the purchase of a minimum quantity of gas whether or not delivery is accepted by the purchaser.

GAS COST RECONCILIATION ACCOUNT (GCRA)

A stabilization mechanism that ensures the rates for gas sales fully recover, but neither over nor under recover, fixed and variable gas costs incurred, regardless of weather and variations which may occur occasionally in the various gas cost components.

GIGAJOULE (GJ)

0.95 thousand cubic feet of natural gas at 1000 Btu per cubic foot or 0.28 megawatt hours of electricity. Terajoule (TJ) is one thousand gigajoules and petajoule (PJ) is one million gigajoules.

INTEGRATED RESOURCE PLANNING

A planning process, used by regulated energy utilities, that equally evaluates changes in energy supply options with changes in energy demand options. The outcome of the process is an integrated resource plan, usually covering 15 to 20 years.

INTERRUPTIBLE CUSTOMERS

Gas customers who choose low priority service, usually at lower rates under schedules or contracts that anticipate and permit interruption of gas service on short notice, generally in peak load seasons.

INTERVENOR

An active participant in a hearing, typically representing one or a group of customers.

NATIONAL ENERGY BOARD

A federal regulatory body that oversees interprovincial and international oil and gas pipelines, as well as the export and import of electricity, oil and gas.

PEAK SHAVING

The process of supplying gas to a utility system from an auxiliary source, such as storage or liquefied natural gas, during periods of maximum demand to reduce the load or demand on the primary source of supply, usually a pipeline.

RATE BASE

The investment in gas plant in service and working capital on which utilities earn a rate of return to compensate shareholders and holders of the utility debt.

REVENUE REQUIREMENT

The total revenues to be generated by rates in order to recover the costs of providing service.

REVENUE STABILIZATION ADJUSTMENT MECHANISM (RSAM)

A mechanism to reduce the impact of weather and other factors on the variability of the Utility's revenues.

SHIPPERS

Entities holding transportation contracts on pipelines which require payment of tolls.

TCF

Trillion (10¹²) cubic feet of natural gas.

TOLLS

The rates charged by pipeline companies under tariffs approved by regulatory bodies for such services as raw gas transmission, processing and transportation.

TRANSPORTATION

A gas delivery service provided by a pipeline or local gas utility company to customers who purchase natural gas directly from producers or brokerage companies.

METRIC TO IMPERIAL CONVERSIONS

1 GJ = 0.9482 MMBtu
1 10³m³ = 35.301 MCF
1 m³ = 6.290 Barrels
1 km = 0.6214 miles

MANAGEMENT DISCUSSION AND ANALYSIS

This discussion and analysis is a review of the operating results, business risks, financial condition and outlook for BC Gas Inc. ("BC Gas" or the "Company"). This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes.

BUSINESS SEGMENTS OF BC GAS

Gas Utility Operations

The Company's gas utility operations consist primarily of BC Gas Utility Ltd. ("BC Gas Utility" or the "Utility") and several small related utility operations. BC Gas Utility is the largest gas distribution utility in British Columbia serving approximately 90% of the province's natural gas users in approximately 100 communities. BC Gas Utility provides transmission and distribution services to its customers, and obtains gas supplies primarily on behalf of residential and commercial customers, making the Utility the largest single buyer of natural gas in B.C. Major areas served are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province.

Oil Pipeline Operations

BC Gas' oil pipeline operations are carried out by Trans Mountain Pipe Line Company Ltd. ("Trans Mountain") which owns and operates a pipeline system transporting crude oil and refined products from Edmonton, Alberta to Burnaby, B.C. The pipeline of a U.S. subsidiary delivers Canadian crude oil to several refineries in Washington State. In addition, Trans Mountain owns and operates a marine terminal in the Port of Vancouver and a jet fuel pipeline to a storage system at Vancouver International Airport.

Related Businesses

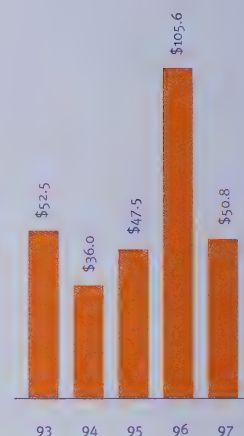
BC Gas has other businesses which include independent power production, energy marketing services, international consulting, development of water related infrastructure projects and retail energy services (the "Related Businesses"). These businesses are either owned by the Company's subsidiary, Inland Pacific Enterprises Ltd. ("IPEL"), or held directly by BC Gas.

In addition to these three business segments, BC Gas incurs interest and other overhead expenses at the Corporate level. The contribution to earnings per share of each segment is as follows:

<i>Years ended December 31</i>	1997	1996
Gas utility operations	\$ 1.25	\$ 1.13
Oil pipeline operations	0.51	0.49
Related businesses	(0.03)	0.03
Corporate (BC Gas Inc.)	(0.10)	(0.17)
	1.63	1.48
Non-recurring items	(0.36)	1.05
Earnings per common share	\$ 1.27	\$ 2.53

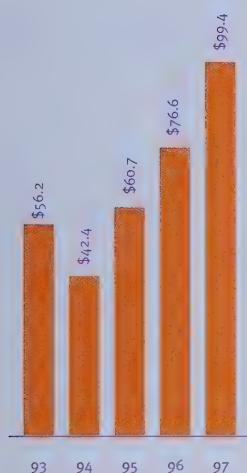
The two major operating subsidiaries of the Company, BC Gas Utility and Trans Mountain, are both regulated companies. The British Columbia Utilities Commission (the "BCUC") regulates BC Gas Utility and the National Energy Board (the "NEB") regulates the Canadian portion of Trans Mountain's crude oil and refined products pipeline system. The applicable regulatory bodies approve rates and tolls for services and the construction of facilities.

Traditionally rates have been set through historical cost rate base and rate of return methodology. More recently, various incentive rate methodologies have been approved and implemented by the regulatory authorities as part of the rate setting process in order to enhance both value to customers and returns to shareholders. The sections on regulation and rates discuss recent changes in the way rates are set for both the gas utility and oil pipeline operations.



**BC Gas Inc.
Net Earnings (\$ millions)**
Earnings in 1996 included
\$44.0 million of
non-recurring items.

MANAGEMENT DISCUSSION AND ANALYSIS



**Gas Utility Operations
Earnings Before Restructuring
Costs, Income Taxes and
Non-Controlling Interest**
(\$ millions)

Since the introduction of regulatory stabilization measures in 1993 and 1994, Gas Utility results are less sensitive to variations in gas costs and weather.

EARNINGS PERFORMANCE

Earnings before non-recurring items were significantly higher in 1997 than in 1996. Net earnings before non-recurring items were \$65.2 million in 1997 versus \$61.6 million in 1996. On a per share basis, net earnings before non-recurring items were \$1.63 per common share in 1997 compared with \$1.48 in 1996. An analysis of the increase in earnings is as follows:

In millions of dollars

Net earnings 1996	\$105.6
1996 Non-recurring items:	
Gain on sale of Inland Gas & Oil	(41.0)
Writedown of U.S. marketing operations	9.7
Utilization of Utility tax loss carry forwards	(12.7)
Continuing earnings 1996	61.6
1997 Lower allowed return on common equity	(3.8)
1997 Growth in rate base and other items	7.4
Continuing earnings 1997	65.2
1997 Non-recurring items:	
NW Energy disposition costs	(9.3)
Restructuring costs	(5.1)
Net earnings 1997	\$ 50.8

GAS UTILITY OPERATIONS

Contribution to Earnings

<i>In millions of dollars</i>	1997	1996
Gross revenues	\$765.8	\$724.3
Operating expenses		
Cost of gas	375.3	363.0
Operations and maintenance	120.8	112.8
Depreciation and amortization	55.4	56.2
Property and other taxes	30.9	28.2
	582.4	560.2
Operating income	183.4	164.1
Financing costs	84.0	87.5
Earnings before restructuring costs, income taxes and non-controlling interest	\$ 99.4	\$ 76.6

Revenues

Revenues from gas utility operations increased to \$765.8 million during 1997 from \$724.3 million in 1996. Because of regulatory deferral accounts which insulate the Utility's profit margins from fluctuations in weather and natural gas costs, variations in reported revenues are caused mainly by changes in gas costs and other components of the Utility's cost of service which are recovered in customer rates. Changes in volumes of gas sold to core market customers due to weather or other factors have a relatively minor impact on reported revenues. In 1997, revenues were higher as a result of increases to both cost of service and cost of gas, which are flowed through into customer rates, higher rate base and an increase in the number of customers serviced by the Utility, offset by a lower authorized return on common equity ("ROE") approved by the BCUC of 10.25% compared with 11.0% the previous year.

During 1997, 15,895 new customers were added, bringing the total number of gas utility customers to 732,316 at year end. This growth in customers was mainly in the heating market for new single-family houses where natural gas continues to achieve a very high market share. This is particularly true for single family detached dwellings near or on existing gas mains in the key service areas of metropolitan Vancouver and the Fraser Valley and interior regions of British Columbia.

Transportation and sales services to industrial customers are not covered by the regulatory rate stabilization mechanisms that reduce the Utility's exposure to fluctuations in sales to residential and commercial customers. Industrial sales service increased by 3,211 terajoules while transportation volumes decreased by 2,226 terajoules from the previous year. The Utility earns approximately the same margin regardless of whether a customer contracts for sales or transportation service.

MANAGEMENT DISCUSSION AND ANALYSIS

BC Gas Utility has a number of firm and interruptible contracts with the British Columbia Hydro and Power Authority ("BC Hydro") Burrard Thermal Plant near Vancouver. The margin from these contracts was \$1.0 million, a decrease of \$0.7 million from 1996. In addition to these contracts, there is a \$5.0 million per annum minimum fixed price contract with a term extending through September 1998. The revenue from this contract is included in other operating revenue. The Company is currently in negotiations with BC Hydro with respect to these contracts as well as a number of other opportunities for providing related gas services to BC Hydro. Should the minimum fixed price contract noted previously not be renewed, the Company anticipates that any revenue shortfalls associated with the expiry of that contract will be deferred and recovered from customers in future rates.

Expenses

Expenses for the gas utility segment of the Company include the cost of gas, operations and maintenance expenses, depreciation and amortization, and property and other taxes. Total operating expenses were \$582.4 million in 1997 compared with \$560.2 million in 1996.

Cost of gas amounted to \$375.3 million in 1997 compared with \$363.0 million in 1996. The increase in cost of gas reflects an increase in the price of natural gas bought by the Utility on behalf of its customers. All gas purchase costs are passed directly through to the Utility's customers.

Operations and maintenance expenses increased to \$120.8 million in 1997 from \$112.8 million in 1996. This increase was due largely to expenditures on business process review initiatives which will result in enhanced productivity in 1998 and beyond, in addition to general inflationary increases, net of productivity gains.

Reduced amortization of deferred charges, relating to lower interest deferral account balances caused by lower interest rates, offset by increased investment in gas plant in service, resulted in depreciation and amortization expense decreasing to \$55.4 million in 1997 from \$56.2 million in 1996.

Growth in the asset base of the Company, in conjunction with higher tax rates, resulted in property and other taxes increasing by \$2.7 million to \$30.9 million in 1997.

Financing costs decreased to \$84.0 million in 1997 from \$87.5 million in the previous year largely as a result of lower short-term interest rates during the year. BC Gas Utility has in place short-term and long-term interest deferral accounts which have been approved by the BCUC to absorb interest rate fluctuations. In 1997, the Utility's interest deferral accounts effectively locked in its cost of short-term funds attributable to regulated assets during the year at 4.0%.

Regulation and Rates - BC Gas Utility

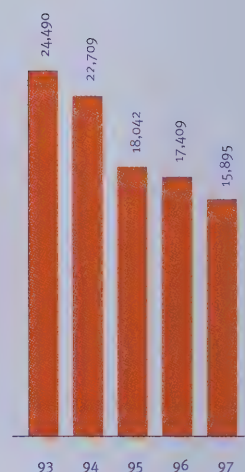
	Mid-year rate base (in millions)	Common Equity	
		Allowed Return	Equity Component
1997	\$1,515.5 ¹	10.25%	33%
1996	\$1,441.2	11.0%	33%
1995	\$1,333.1	12.0%	33%
1994	\$1,201.5	10.65%	33%

¹preliminary

Allowed Return on Equity

The Utility's 1997 allowed ROE of 10.25% was determined based on a formula that applied a 300 basis point risk premium to a forecast of long-term Government of Canada bond yields. The decline from 11.0% in 1996 was a result of a forecast decline in long-term bond yields.

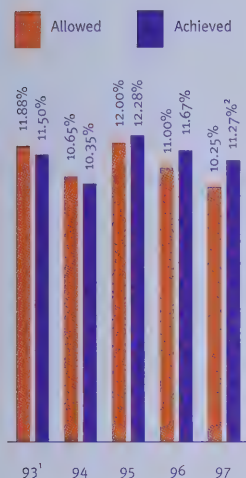
In a decision dated April 24, 1997, the BCUC amended the formula so that the change in the ROE will be only 80% of the change in the forecast long-term bond yield, down from 100% under the previous formula. In addition, the starting point from which changes in the forecast bond yield are



Gas Utility Operations Customer Additions

Since 1992, BC Gas Utility's customer base has increased 15 per cent to 732,316.

MANAGEMENT DISCUSSION AND ANALYSIS



**BC Gas Utility Ltd.
Allowed vs. Achieved
Utility Return On Equity**

Recent declines in allowed returns due to lower interest rates have been partially offset by gains from improved operating results and incentive regulation.

¹implied

²preliminary

calculated was increased from 7.75% to 9.25%. If these changes had been in effect for the 1997 ROE calculation, the 1997 allowed ROE would have been 10.50% instead of 10.25%.

For 1998, the Utility's allowed ROE has been set at 10.0% using the revised formula, reflecting a continued decline in forecasted long-term bond yields. Had the formula not been revised, the 1998 allowed ROE would have been 9.50%.

1998-2000 Revenue Requirement Decision

BC Gas Utility's revenue requirements for 1997 were determined based on a negotiated settlement between the Utility and its major intervenors which covered the years 1996 and 1997. In February, 1997, BC Gas Utility filed a performance-based rate plan with the BCUC to set the Utility's revenue requirements for the years 1998 to 2002. In its application BC Gas Utility proposed the continuation and expansion of the formula-based approach to determining a variety of components of cost of service, including revenues, operating expenses, and allowed return on common equity. The Utility requested a new incentive for the efficient management of capital expenditures, continuation of the gas supply incentive, and proposed an earnings sharing mechanism to allow customers to share in earnings over and above the allowed return on equity.

In processing the application BC Gas Utility, BCUC staff and other interested parties utilized an Alternative Dispute Resolution process to identify, define and reduce the issues in question in a similar manner as the processes undertaken for several prior revenue requirement and other applications. This resulted in the Utility and the other interested parties reaching a negotiated settlement on June 26, 1997, which was approved by the BCUC on July 23, 1997.

The key points of the settlement are as follows:

- The settlement is for the three years 1998, 1999 and 2000;
- Cost recovery implicit in the 1998 to 2000 rates requires BC Gas Utility to achieve real productivity gains in operating and maintenance costs of 2% in each of 1998 and 1999 and 3% in 2000. Restructuring costs of up to \$3 million associated with achieving these productivity targets can be deferred and recovered in customer rates;
- Commencing January 1, 1998, new incentives for demand side management activities and capital expenditure efficiency are available. To the extent that demand side management programs exceed targets, and to the extent that unit costs of certain classes of capital expenditures are lower than the allowed level, the Utility will have opportunities to generate earnings incremental to what would be allowed in a conventional regulatory framework;
- An earnings sharing mechanism is incorporated whereby variances in achieved return on equity from that allowed by the BCUC in a given year are to be shared equally with customers. Earnings from the established incentive programs are not included in the earnings sharing mechanism;
- The ratio of overheads capitalized is to be reduced from 22.5% in 1997 to 20% in 1998 and 1999, and to 16% in 2000;
- The allowed common equity component is to remain at 33% of capitalization, and \$150 million of outstanding first preference shares are to be refinanced with long-term debt as they become redeemable in 1999 and 2000.

The Off-System Incentive Program for mitigating gas supply costs to customers which was in place during the 1996-97 revenue requirement settlement was renegotiated with BCUC staff and other interested parties separately from the 1998-2000 revenue requirement settlement process. A revised gas supply incentive program was approved by the BCUC on December 4, 1997. The revised Gas Supply

MANAGEMENT DISCUSSION AND ANALYSIS

Mitigation Incentive Plan measures results in reducing gas supply costs to customers more broadly than the previous program, and reduces the risk to shareholders of poor results while correspondingly reducing the potential opportunities for shareholders when the program has strong results. It is expected that the benefits to shareholders under the revised program will be substantially less than the \$4.6 million (pre-tax) which accrued to shareholders in 1997.

Southern Crossing Pipeline Application

BC Gas Utility has applied to the BCUC for a Certificate of Public Convenience and Necessity ("CPCN") in regards to the proposed Southern Crossing Pipeline ("SCP"). The SCP, which is estimated to cost approximately \$348 million, includes 312 kilometres of 24 inch (610 mm) pipeline to be constructed from Yahk, B.C. in the south-eastern corner of the province to Oliver, B.C. at the south end of the Okanagan valley, as well as related compression facilities. The routing will primarily follow existing pipeline rights-of-way.

The BCUC convened a hearing on the CPCN application on October 14, 1997 which was completed in December 1997. A decision is expected from the BCUC in March 1998. In addition, the Utility filed its application for a Project Approval Certificate with the B.C. Environmental Assessment Office in January 1998 and the Company anticipates that approval will be received by mid-1998. With timely approvals, the Company believes that the pipeline could be in service by November 1, 1999.

Business Risks

Regulatory Treatment

BC Gas Utility, through the rate-making process, relies on the BCUC to set rates that will allow the Utility to earn a fair return for its common shareholders. In addition, the BCUC approves the allowable cost of providing service, the capital structure employed to finance the Utility's investment

in plant and equipment, and various other aspects of the Utility's operation. Fair regulatory treatment that allows the Utility to fully recover its investment in plant and equipment and to earn a risk adjusted rate of return comparable to that available on alternative investments is essential for ongoing success.

In management's view, the successful negotiation and approval of the 1998-2000 Revenue Requirement settlement is another positive step in the evolution of the Utility's regulatory relationship with the BCUC and its customers. The settlement demonstrates that incentive regulatory arrangements have gained the support of the BCUC and customer groups as an approach that can streamline the regulatory process while implementing incentives which benefit both customers and shareholders.

Long-Term Competitiveness

As the energy industry in North America continues to experience structural change, it is essential that BC Gas Utility challenge the level of ongoing operating expenses and commitment of capital resources. Management of the Utility has worked with the BCUC to incorporate productivity targets, in the form of decreased operations and maintenance spending per customer of 2%, 2% and 3% for 1998, 1999 and 2000 respectively. In addition, a new capital expenditure efficiency mechanism was incorporated into the 1998-2000 settlement, and policies for mains extensions continue to be refined and improved, thereby reducing the required net investment in each new customer addition.

Future competition in the energy market will introduce new risks to BC Gas Utility. Challenging its own investment criteria, as well as those imposed on its customers from external forces, is an important component of the Utility's strategy for maintaining the long-term competitive position of natural gas as an economic source of energy for British Columbians.

MANAGEMENT DISCUSSION AND ANALYSIS

Customer Additions

In recent years, British Columbia has experienced a decline in immigration and housing starts, which has translated into a decline in the rate of customer additions for the Utility. BC Gas Utility continues to achieve an extremely high penetration rate among single-family detached homes on or near existing gas mains. The Company has not realized the same high success rate in other housing markets, such as multi-family developments. To the extent that population growth and housing starts decline, the Utility will likely not be able to connect customers at the same rate as it has in the past. Likewise, if the proportion of single-family detached dwellings declines, BC Gas Utility may see a further decline in customer additions.

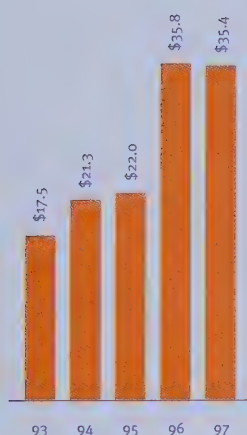
Gas Supply

BC Gas continues to face significant physical risk related to gas supply disruption as it is dependent on a limited selection of pipeline and storage providers. This risk is particularly acute in the Vancouver-Lower Mainland service area where the majority of BC Gas Utility's core market customers are located. These customers rely primarily on the transportation services of one pipeline company. In addition, the limited transportation and storage alternatives present risks of both supply disruption and lack of access to competitive sources of natural gas.

To the extent possible, BC Gas Utility has attempted to minimize gas supply and price risk through the use of long-term transportation, storage and supply contracts, hedging instruments and a diverse supply portfolio. In 1997, management has actively pursued several initiatives to allow for the transportation of gas supplies through alternate pipeline infrastructure. Specifically, BC Gas Utility's application before the BCUC for the Southern Crossing Pipeline was intended to address this risk as well as to minimize the delivered cost of gas to the Utility's core customers.

During the SCP hearing before the BCUC in the Fall of 1997, it became apparent from the evidence of several participants in the hearing that the regional peak day demand in British Columbia and the U.S. Pacific Northwest significantly exceeds the supply available from the existing infrastructure. Management believes that the SCP is an integral factor in meeting the growing demands for natural gas as well as reducing consumer exposure to supply disruptions and related price increases should the region experience either a cold winter or failure in gas producing, storage or pipeline facilities.

In addition, BC Gas is monitoring with interest the Alliance Pipeline project, which would transport natural gas from northern British Columbia to Chicago, as it has the potential to alter the supply of B.C. basin gas available to consumers in British Columbia. The Alliance Pipeline, which is awaiting regulatory approval, is expected to transport up to 600 Mmcfd, or approximately 25% of current production levels in northern B.C., away from the province as early as 2000. Projects such as Alliance underscore the need to have competitive access to alternate gas supply sources in order to ensure reliable supply and reasonable gas supply costs for gas consumers in British Columbia.



**Oil Pipeline Operations
Earnings Before
Income Taxes and
Non-Controlling Interest**
(\$ millions)

Earnings have benefited from higher transportation volumes and incentives achieved under the five-year settlement.

OIL PIPELINE OPERATIONS

Contribution to Earnings

<i>In millions of dollars</i>	1997	1996
Gross revenues	\$129.1	\$132.8
Operating expenses		
Operations and maintenance	44.5	47.2
Depreciation and amortization	15.8	15.3
Property and other taxes	20.0	19.2
	80.3	81.7
Operating income	48.8	51.1
Financing costs	13.4	15.3
Earnings before income taxes and non-controlling interest	\$ 35.4	\$ 35.8

MANAGEMENT DISCUSSION AND ANALYSIS

Revenues

Revenues from oil pipeline operations decreased to \$129.1 million in 1997 from \$132.8 million in 1996. The decline in revenues was mainly due to lower delivery volumes than the strong volumes seen in 1996. Petroleum and other pipeline deliveries averaged 39,802 cubic metres per day (m³/d) in 1997 compared to 43,039 m³/d in 1996.

Delivery volumes in 1997, particularly light crude deliveries for export to tankers and to connected refineries in Washington State, reflect increasing crude production from the Western Canada Sedimentary Basin resulting from new production of heavy crude and sustained light crude production levels. The overall decrease in volumes from 1996 levels is primarily a result of reductions in deliveries of refined products and crude oil shipments to export markets. The decline in refined product volumes reflects a reduction in supply following a fire at an Edmonton refinery and the diversion of available refined product volumes to the prairie markets in response to high seasonal demand. The decline in crude oil volumes reflects the unusually high levels experienced in 1996, when ongoing capacity constraints on the Interprovincial Pipe Line Inc. ("Inter-provincial") system caused light crude oil to be diverted to Washington State and offshore markets.

Expenses

Operating expenses from oil pipeline operations decreased by \$1.4 million from \$81.7 million in 1996 to \$80.3 million in 1997 mainly as a result of a reduction in transportation expenses associated with lower delivery volumes. Financing costs decreased from \$15.3 million to \$13.4 million as a result of lower interest rates and debt levels.

Regulation

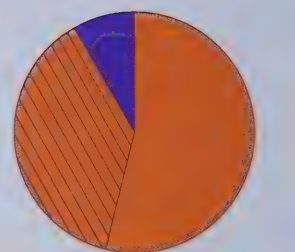
In October, 1995, Trans Mountain entered into negotiations with the Canadian Association of Petroleum Producers and the principal shippers on the pipeline system. Those negotiations resulted in an agreement

which was approved by the NEB. The agreement provides for the determination of Trans Mountain's revenue requirement, and resulting tolls, over a five year period which started on January 1, 1996. Trans Mountain's revenue requirement is determined with reference to a negotiated 1996 starting point of \$106.0 million, which includes a 1996 provision for income taxes of \$7.5 million. Each successive year's starting point, net of income taxes, will be adjusted to reflect the yearly rate of change of the Consumer Price Index of Canada.

The negotiated settlement allows Trans Mountain to retain 100% of earnings up to \$13 million, after which earnings are shared 50/50 with the shippers in accordance with the efficiency incentive. In addition, Trans Mountain shares with its shippers on a 50/50 basis certain incremental revenues resulting from an excess capacity incentive. The total pre-tax revenues to be credited to the shippers in 1998 as a result of these sharing arrangements was \$1.9 million. Trans Mountain will recover from the shippers approximately \$2.0 million in 1998 due to lower than forecast volumes shipped in 1997.

The toll charged for the portion of the pipeline located in Washington State falls under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Regulation by FERC is on a complaint basis. There were no complaints in 1997.

Tolls for the jet fuel pipeline system are regulated by the BCUC on a complaint basis. A complaint which was filed regarding the 1997 tolls was resolved. In 1997 Trans Mountain conducted negotiations with the principal shippers on the jet fuel pipeline system. Those negotiations resulted in a proposed agreement to determine the jet fuel pipeline revenue requirement in a manner substantially similar to the agreement currently in place for the crude oil and refined products pipeline. The agreement, which will operate for a five year period commencing January 1, 1998, remains subject to approval of the BCUC.



■ Canadian mainline
■ US mainline
 (included in Canadian mainline)
■ Jet fuel deliveries

Oil Pipeline Operations
1997 Transportation Volumes
 (m³/day)

U.S. pipeline and jet fuel

volumes have grown

54 per cent and 45 per cent
 respectively since 1993.

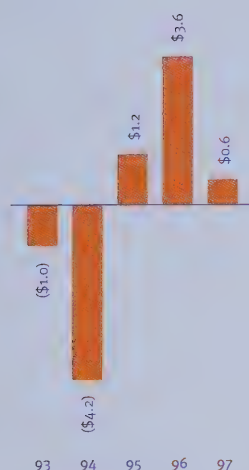
MANAGEMENT DISCUSSION AND ANALYSIS

Business Risks

Trans Mountain has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. General risks faced by Trans Mountain include the following.

- Revenues may be reduced if expected throughput levels do not materialize in 1998. Under the incentive toll settlement, this risk is mitigated by a mechanism which permits Trans Mountain to carry forward a throughput related revenue shortfall for recovery in the subsequent year. However, there is no assurance that the level of throughput required for recovery of any accumulated shortfall will materialize in a subsequent year. The mitigating measures do not apply with respect to the portion of the pipeline within the United States.
- Refined products can be imported for the B.C. market through offloading facilities in the Port of Vancouver or by truck transportation from refineries in Washington State. In 1997, refined products for the B.C. market represented approximately 30% of Trans Mountain's deliveries. This risk may be mitigated by the adjustment mechanism described above.
- The decision by the NEB requiring Trans Mountain to use the taxes payable method rather than the tax allocation method of accounting for income taxes, which will inevitably result in higher tolls as capital cost allowance benefits are expended, is predicated on the assumption that future shippers will still ship under such increased tolls.
- The pipeline industry is currently addressing the issue of negative salvage values and the risk that the cost of abandonment of the plant at the end of its useful life will not be fully recovered in tolls. Until such time as the magnitude of and the funding mechanism for the eventual recovery of negative salvage is determined, Trans Mountain, like other Canadian trunk pipeline systems, makes no provision for these amounts.

- Trans Mountain maintains a comprehensive Line Integrity Program as a preventive measure to mitigate the risk of a pipeline failure or other loss of system integrity. The Program is intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a loss of line integrity.
- Total pipeline capacity out of western Canada increased in 1997 with the expansion of the Interprovincial system and the completion of the Express Pipeline system, a crude oil pipeline from Alberta to Wyoming with ongoing connections to midwest refineries. While net prices received by producers by shipping on the Express system are not expected to be as attractive as those from the alternative of shipping on Trans Mountain's or Interprovincial's systems, there are ongoing producer/shipper commitments to ship on the Express system. To the extent these commitments are fulfilled, the volumes of Alberta crude oil production that will be available to Trans Mountain, Interprovincial and other Alberta export pipeline systems will be reduced.



Related Businesses Earnings Before NW Energy Disposition Costs, Income Taxes and Non-Controlling Interest (\$ millions)

Reduced earnings in 1997 reflect the 1996 sale of Inland Gas & Oil.

RELATED BUSINESSES

Contribution to Earnings

<i>In millions of dollars</i>	1997	1996
Gross revenues	\$ 39.0	\$ 45.1
Operating expenses		
Operations and maintenance	16.0	15.9
Depreciation, depletion and amortization	6.7	8.8
Property and other taxes	1.6	1.6
	24.3	26.3
Operating income	14.7	18.8
Financing costs	14.1	15.2
Earnings before NW Energy disposition costs, income taxes and non-controlling interest	\$ 0.6	\$ 3.6

MANAGEMENT DISCUSSION AND ANALYSIS

Related Businesses earnings in 1997 were \$0.6 million before NW Energy disposition costs, income taxes and non-controlling interest compared with \$3.6 million in 1996. The reduction in gross revenues and depreciation, depletion and amortization expense was primarily a result of the sale of Inland Gas & Oil Ltd. ("Inland Gas & Oil") in August 1996. The reduction in financing costs was due to reduced debt levels through scheduled principal repayments. After provision for income taxes and non-controlling interest, the loss from related businesses before NW Energy disposition costs was \$1.3 million in 1997 compared to earnings of \$1.3 million in 1996.

Business Risks

The Related Businesses primarily operate in unregulated industries and are, by their nature, more risky than BC Gas' regulated operations. Therefore, it is difficult to predict the timing and magnitude of any contribution these businesses will make to the Company's future earnings. Management is optimistic, however, that these companies will become important contributors to the future earnings growth of the Company.

CORPORATE RESULTS

Contribution to Earnings

Corporate results relate to the operations of BC Gas Inc., the parent company of the BC Gas group of companies. Although revenue is not directly generated by the parent company, BC Gas does incur expenses associated with managing the investments in its various subsidiaries.

<i>In millions of dollars</i>	1997	1996
Operating expenses		
Operations and maintenance	\$ 2.9	\$ 1.7
Depreciation and amortization	–	0.2
Other losses	–	0.8
Operating loss	(2.9)	(2.7)
Financing costs	3.2	8.5
Loss before income taxes and non-controlling interest	\$ (6.1)	\$ (11.2)

The losses incurred by the Corporate entity are primarily a result of the costs associated with interest expense incurred on debt used to finance the Company's investments in its subsidiaries. Other than dividends received from investments in its subsidiaries, the Corporate entity has virtually no source of revenue.

Corporate overhead such as salaries and rent comprise the \$2.9 million of operations and maintenance expenses incurred in 1997, up from \$1.7 million in 1996. Other losses of \$0.8 million in 1996 mainly represent write-downs of certain investments held at the Corporate level.

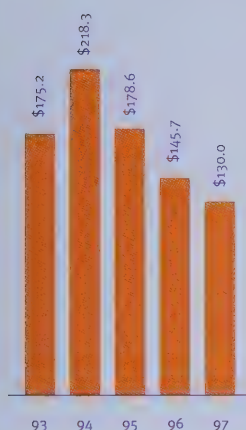
Financing costs, representing interest expense at the Corporate entity, were \$3.2 million in 1997, a reduction of \$5.3 million from the \$8.5 million incurred in 1996. This decrease was mainly due to the cash proceeds received on the sale of Inland Gas & Oil effective August 16, 1996, offset by borrowings for the Company's share repurchase program. The remainder of the interest expense reduction was principally a result of lower interest rates in 1997 compared to the previous year.

NON-RECURRING ITEMS

NW Energy Disposition Costs

The Company has incurred \$13.7 million (\$9.3 million or \$0.23 per share after tax) of costs in anticipation of the disposition of its interest in NW Energy (Williams Lake) Limited Partnership ("NW Energy"). Discussions with BC Hydro relating to certain aspects of the electricity purchase agreement between NW Energy and BC Hydro are continuing but have not been completed. Given this situation, the Company determined that it is prudent to write off these costs in the year ended December 31, 1997.

MANAGEMENT DISCUSSION AND ANALYSIS



**BC Gas Inc.
Consolidated
Capital Expenditures**
(\$ millions)

1997 capital expenditures reflect fewer gas utility customer additions and the 1996 sale of Inland Gas & Oil Ltd.

Restructuring Costs

The Company has recorded a pre-tax provision of \$9.4 million (\$5.1 million or \$0.13 per share after tax) for costs relating to the restructuring program in BC Gas Utility. Annualized cost reductions resulting from this program, once fully implemented, will amount to approximately \$16.9 million. The majority of these productivity benefits flow to customers in rates under the terms of the 1998-2000 Revenue Requirement settlement.

NON-CONTROLLING INTEREST

<i>In millions of dollars</i>	1997	1996
Dividends on preference shares	\$ 4.7	\$ 4.7
Recovery of Part VI.1 tax resulting from the utilization of prior years' losses	—	(2.0)
NW Energy	1.1	1.2
	\$ 5.8	\$ 3.9

The increase in the non-controlling interest share of current earnings was primarily due to the recovery in 1996 of Part VI.1 tax on preference share dividends resulting from the utilization of prior years' losses, which reduced 1996 non-controlling interest by \$2.0 million.

LIQUIDITY AND CAPITAL RESOURCES

Changes in non-cash operating working capital, offset by a decrease in net earnings after adjusting for items not involving cash, resulted in an increase in cash flow from operations to \$170.6 million in 1997 from \$166.8 million in 1996. The reduction in 1997 net earnings after adjusting for items not involving cash reflects the NW Energy disposition costs and restructuring costs noted previously under "Non-Recurring Items".

Capital expenditures on property, plant and equipment totalled \$130.0 million in 1997 compared with \$145.7 million in 1996. The \$15.7 million reduction in capital spending was due primarily to the sale of Inland Gas & Oil, which invested \$17.6 million in petroleum and natural gas properties in 1996.

The capital spending in 1997 is summarized as follows:

In millions of dollars

Gas utility operations	
Mains, services and engineering projects	\$ 49.3
Land and buildings	2.3
Systems and computer hardware	16.1
Other	5.1
	72.8
Capitalized overhead	32.6
	105.4
Oil pipeline operations	23.6
Related businesses	1.0
	\$130.0

Coverage Ratios

Due to the capital intensive nature of the Company's businesses and the need to raise debt frequently in the fixed income market, maintenance of its financial ratios is a priority for BC Gas. The most significant ratios are considered to be interest coverage and total debt to shareholders' equity. These are presented below on a consolidated basis for the three corporate entities actively issuing debt in the capital markets:

	1997	1996
Interest coverage		
BC Gas	2.13	1.83
BC Gas Utility	2.14	1.87
Trans Mountain	3.88	3.42
Debt to shareholders' equity		
BC Gas	2.49:1	2.25:1
BC Gas Utility	1.71:1	1.76:1
Trans Mountain	1.22:1	1.40:1

Debt Ratings

Securities issued by BC Gas, BC Gas Utility and Trans Mountain are rated by two Canadian bond rating companies, the Dominion Bond Rating Service ("DBRS") and the Canadian Bond Rating Service ("CBRS"). The ratings assigned to securities issued by the BC Gas group of companies

MANAGEMENT DISCUSSION AND ANALYSIS

are reviewed by DBRS and CBRS on an annual basis. The table below summarizes the ratings assigned to the Company's various securities at December 31, 1997.

	DBRS	CBRS
BC Gas Inc.		
Commercial paper	R-1(Low)	A-1(Low)
BC Gas Utility		
Commercial paper	R-1(Low)	A-1
Unsecured debentures	A	B++
Medium term note debentures and medium term notes	A	B++
Purchase money mortgages	A	A(Low)
7.10% Preference shares	Pfd-3	P-3(High)
6.32% Preference shares	Pfd-3	P-3
Trans Mountain		
Commercial paper	R-1(Low)	A-1(Low)
Unsecured debentures	A(Low)	A(Low)

Projected Capital Expenditures

BC Gas has estimated total capital expenditures of \$183.6 million in 1998 for all of its subsidiaries, which the Company expects to finance with a combination of long-term debt issuance at BC Gas Utility, short-term borrowings and internally generated funds. The breakdown of projected capital expenditures for 1998 is as follows:

In millions of dollars

Gas utility operations	
Mains, services and engineering projects	\$ 75.4
Land and buildings	17.7
Systems and computer hardware	33.8
Other	12.5
	139.4
Capitalized overhead	29.2
	168.6
Oil pipeline operations	15.0
	<u>\$183.6</u>

Public Issues

During the year, BC Gas Utility issued \$55 million of medium term note debentures at an interest rate of 6.20%. This compares with \$20 million issued in 1996 at an interest rate of 6.75%.

Lines of Credit

The Company has lines of credit totalling \$675 million to finance cash requirements, comprising \$200 million at BC Gas Inc., \$350 million at BC Gas Utility and \$125 million at Trans Mountain. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issued by each company. Bank lines of \$298 million were unutilized at the end of 1997. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime.

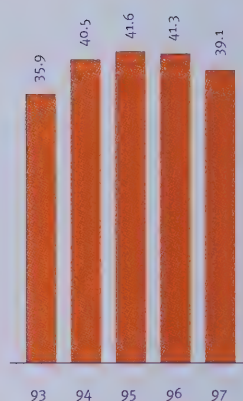
Common Share Repurchase Program

In July 1996, BC Gas announced a Normal Course Issuer Bid for 2,300,000 common shares of the Company for the period of August 15, 1996 to August 14, 1997. In June 1997, the repurchase program was increased to 4,100,000 shares, and was subsequently extended to August 14, 1998.

In the year ended December 31, 1997, 2,209,400 common shares were purchased in the open market at an average purchase price of \$23.47 per share, as compared to 865,500 shares purchased at an average price of \$19.35 per share in 1996.

Dividends

The dividends paid on BC Gas' common shares in 1997 were \$0.975 per share, up from \$0.90 per share in 1996. In aggregate, BC Gas paid common shareholder dividends of \$39.1 million in 1997 compared to \$37.6 million in 1996. The increase in the total dollar amount of dividends paid reflects the increased dividend per share, offset by a decrease in the average number of common shares outstanding in 1997 due to the share repurchase program.



BC Gas Inc.
Common Shares Publicly Held
at Year End
(millions)

Since August 1996,

BC Gas has repurchased
3.1 million common shares,
representing
6.6 per cent of shares
outstanding.

MANAGEMENT DISCUSSION AND ANALYSIS

Financial Instruments and Risk Management

The Company uses financial instruments to manage its exposure to changes in interest rates where the interest rate risk is not managed through the use of interest rate deferral accounts. These financial instruments are only used for hedging purposes, and are only employed in connection with an underlying asset or liability through counterparties with acceptable credit status. The interest rate hedging instruments in place at December 31, 1997 all mature in 1998 and have effective interest rates between 5.6% and 8.1%. As at December 31, 1997, the Company had fixed the rate on a total of \$27 million of floating rate debt using interest rate hedging instruments.

BC Gas, through its gas utility operations, has undertaken a natural gas price risk management program on behalf of its customers to manage the price volatility of its forecast system gas supply. Part of this program involves the use of financial instruments to effectively fix the price of baseload gas supply. In addition, the Company uses financial instruments in its gas marketing activities to hedge the risks of purchasing and selling natural gas on different terms.

OTHER MATTERS

Year 2000 Issue

The Year 2000 issue refers to the risk that computers and other devices that rely on microprocessor technology may fail to recognize the year 2000 if their program logic uses two digits to represent years. The Company continues to review its major financial and management information systems and is in the process of upgrading these systems to address identified Year 2000 risks. This includes the installation of a new business information system at BC Gas Utility Ltd. The implementation of this new system is scheduled to be completed by the end of

1998. The Company will continue to follow its plan to ensure Year 2000 compliance in its business systems and, at this time, does not anticipate that the costs associated with upgrading financial and management information systems for Year 2000 compliance will have a material earnings impact.

The Year 2000 issue may also impact other equipment such as process control equipment, telecommunication equipment and other devices which make use of microprocessor technology. These are often referred to as "embedded systems". The Company's review of embedded systems is currently in progress. The extent of upgrades to embedded systems has not yet been fully identified. The target date for completing the review of the impact of Year 2000 on embedded systems and the development of detailed plans to address the risks identified is June 30, 1998. Costs related to addressing this issue for embedded systems have not yet been fully quantified, however costs which relate to the regulated operations of the Company are not anticipated to have a material earnings impact.

The impact of Year 2000 regarding relationships with customers, suppliers and other stakeholders is also an area of concern. This is particularly true where the Company is relying on the computer systems of third parties to provide data to the Company's systems or where such third party computer systems perform functions critical to the operations of the business. The Company is currently reviewing the potential impact of these third party relationships in the event of a Year 2000 related system failure of a third party system. The target date for completion of this review and development of plans to manage any significant risks identified is June 30, 1998.

The Company has established a Year 2000 program management office to coordinate and manage all Year 2000 projects on an enterprise wide basis.

MANAGEMENT DISCUSSION AND ANALYSIS

Purchase of NW Energy Interest

On August 5, 1997, the Company purchased the remaining one-third interest in NW Energy it did not already own at a price of \$29.0 million in anticipation of the disposition of a 100% interest in NW Energy to third party investors. As noted previously under "Non-Recurring Items", the Company has not disposed of its interest in NW Energy pending the completion of discussions with BC Hydro relating to certain aspects of the electricity purchase agreement.

Sale of Inland Pacific Energy Services Corp.

On July 31, 1997, the Company sold its ownership interest in Inland Pacific Energy Services Corp., a Spokane, Washington-based energy marketing company. This transaction is not expected to have a material impact on operating results in the future. The Company remains actively involved in energy marketing through its wholly-owned subsidiary, Inland Pacific Energy Services Ltd., based in Vancouver, B.C.

Collective Agreements

Collective agreements with BC Gas Utility employees represented by the Office and Professional Employees International Union (Local 378) and the International Brotherhood of Electrical Workers (Local 213) expire March 31, 1998. Negotiations are currently underway.

OUTLOOK

The Company is focused on building value for customers and shareholders through the creation of added value for customers. The multi-year, negotiated regulatory arrangements in place at BC Gas Utility and Trans Mountain Pipe Line provide an appropriate framework for enhancing customer value and improving the Company's competitive cost position.

As the largest natural gas distributor in British Columbia, BC Gas Utility is well positioned to thrive in a less regulated and more competitive environment. Competition from non-utility participants in the energy services business as well as from utilities

outside the province is expected to increase as the utility environment becomes less regulated and increasingly focused on delivering choices for customers. Changes underway to improve productivity and realign internal systems to a market orientation are expected to improve the Company's ability to deliver high quality products and services at a competitive price. In addition, the introduction of *Homeworks*® and other initiatives provides a foundation for delivering products and services outside the regulated environment.

Although the economy in British Columbia is expected to grow at a lower rate than previous years, BC Gas Utility's exposure to an economic slowdown is relatively limited, given its mature, diversified customer base and its ability to correct for unanticipated developments in the annual rate resetting process. As a result of the lower economic growth rate, the number of customer additions may decline, thereby slowing earnings growth for BC Gas Utility. In addition, a decline in the number of customer additions and in industrial revenues could also impact earnings over the short term until these developments are reflected in the annual rate resetting process.

Trans Mountain's delivery volumes will continue to be affected by the relative price competitiveness of Alberta crude oil in the western North American market and by capacity additions on pipelines out of Edmonton. As the only pipeline connecting Alberta with the continent's west coast, over the long term Trans Mountain is well positioned to capitalize on growing demand created by declining Alaska and California crude oil production.

With the opportunities presented by incentive regulation and the activities currently underway to improve productivity and refocus the Company on the customer's needs, BC Gas will continue to meet the challenges presented by deregulation and increasing competition and enhance shareholder value by creating customer value.

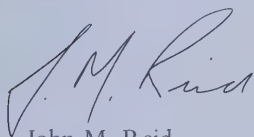
MANAGEMENT'S RESPONSIBILITY

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These statements have been prepared in conformity with generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgements. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG, the auditors appointed by the shareholders, have reviewed the systems of internal control and examined the consolidated financial statements in accordance with generally accepted auditing standards to enable them to express an independent opinion on the financial statements. Their report is set out below.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the financial statements for issuance to the shareholders.



John M. Reid
President and Chief Executive Officer

Vancouver, Canada
February 3, 1998



Milton C. Woensdregt
Senior Vice President, Finance
and Chief Financial Officer and Treasurer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated statements of financial position of BC Gas Inc. as at December 31, 1997 and 1996 and the consolidated statements of earnings, retained earnings and changes in financial position for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1997 and 1996 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles. As required by the Company Act (British Columbia), we report that, in our opinion, these principles have been applied on a consistent basis.



Chartered Accountants
Vancouver, Canada
February 3, 1998

CONSOLIDATED STATEMENTS OF EARNINGS*In millions of dollars, except per share amounts**Years ended December 31*

	1997	1996
REVENUES		
Gas sales	\$ 715.0	\$ 670.9
Petroleum transportation and terminalling	128.5	132.2
Electricity sales	32.3	31.3
Gas transportation	28.6	33.9
Other operating revenue (note 6)	29.5	24.4
Petroleum and natural gas production	–	8.7
	933.9	901.4
EXPENSES		
Cost of gas	375.2	363.0
Operation and maintenance	184.2	173.6
Depreciation and amortization	77.9	78.4
Property and other taxes	52.6	49.0
Petroleum and natural gas production, and depletion	–	6.1
	689.9	670.1
OPERATING INCOME	244.0	231.3
Financing costs (note 8)	114.7	126.5
Other (gains) and losses (note 9)	13.7	(36.8)
Restructuring costs (note 10)	9.4	–
Earnings before income taxes and non-controlling interest	106.2	141.6
Income taxes (note 11)		
Current	56.6	52.7
Deferred	(7.0)	–
Reduction of income taxes due to application of prior years' losses	–	(20.6)
	49.6	32.1
Earnings before non-controlling interest	56.6	109.5
Non-controlling interest (note 4)	5.8	3.9
NET EARNINGS	\$ 50.8	\$ 105.6
Common shares – weighted average (millions)	40.1	41.8
EARNINGS PER COMMON SHARE	\$ 1.27	\$ 2.53

See accompanying significant accounting policies and notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS*In millions of dollars**Years ended December 31*

	1997	1996
Balance, beginning of year	\$ 153.7	\$ 89.1
Net earnings	50.8	105.6
	204.5	194.7
Dividends on common shares	39.1	37.6
Common shares and share options purchased <i>(note 5)</i>	29.9	5.7
Reduction of income taxes related to share issue costs	(0.6)	(2.3)
	68.4	41.0
Balance, end of year	\$ 136.1	\$ 153.7

See accompanying significant accounting policies and notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

*In millions of dollars**December 31***1997**

1996

ASSETS

Current assets

Cash and short-term investments

\$ – \$ 29.4

Accounts receivable

156.4 239.6

Inventories of gas in storage and supplies

26.7 29.7

Prepaid expenses

5.8 6.5

188.9 305.2

Property, plant and equipment *(note 1)*

2,116.1 2,062.6

Other assets *(note 2)*

83.1 59.3

\$ 2,388.1 \$ 2,427.1**LIABILITIES AND SHAREHOLDERS' EQUITY**

Current liabilities

Bank indebtedness

\$ 2.5 \$ –

Short-term notes

374.0 375.9

Accounts payable and accrued liabilities

164.3 224.9

Income and other taxes payable

34.7 19.2

Rate stabilization accounts

24.4 17.3

Current portion of long-term debt *(note 3)*

96.8 10.9

696.7 648.2

Long-term debt *(note 3)*

993.3 1,033.9

Deferred income taxes

34.9 38.9

Non-controlling interest *(note 4)*

75.0 75.4

1,799.9 1,796.4

Shareholders' equity

Capital stock *(note 5)*

369.7 387.8

Contributed surplus *(note 5)*

133.4 140.2

Retained earnings

136.1 153.7

639.2 681.7

Less cost of common shares held by Trans Mountain

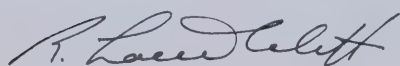
51.0 51.0

588.2 630.7

Commitments *(note 14)***\$ 2,388.1 \$ 2,427.1**

See accompanying significant accounting policies and notes to consolidated financial statements.

Approved by the Board:

Ronald L. Cliff
DirectorJohn M. Reid
Director

CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

*In millions of dollars**Years ended December 31*

	1997	1996
Cash provided by (used for)		
OPERATIONS		
Net earnings	\$ 50.8	\$ 105.6
Items not involving cash		
Depreciation, depletion and amortization	77.9	80.4
Other (gains) and losses	–	(36.8)
Other	(7.0)	2.8
	121.7	152.0
Changes in non-cash operating working capital	48.9	14.8
	170.6	166.8
INVESTMENTS		
Property, plant and equipment	(130.0)	(128.1)
Petroleum and natural gas properties	–	(17.6)
Acquisition of remaining interest in NW Energy (note 9)	(29.0)	–
Net proceeds from disposal of petroleum and natural gas properties (note 9)	–	103.5
Other	8.2	1.2
	(150.8)	(41.0)
FINANCING		
Reduction of short-term notes	(1.9)	(74.1)
Increase in long-term debt	56.1	21.2
Reduction of long-term debt	(10.8)	(10.4)
Issue of common shares	0.6	7.6
Common shares and share options purchased	(55.4)	(17.1)
Dividends on common shares	(39.1)	(37.6)
Other	(1.2)	0.6
	(51.7)	(109.8)
Increase (decrease) in cash	(31.9)	16.0
Cash, beginning of year	29.4	13.4
Cash (bank indebtedness), end of year	\$ (2.5)	\$ 29.4

Cash is defined as cash and short-term investments or bank indebtedness.

See accompanying significant accounting policies and notes to consolidated financial statements.

SIGNIFICANT ACCOUNTING POLICIES

Years Ended December 31, 1997 and 1996

The preparation of these consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts in the financial statements and the disclosure of contingent assets and liabilities. A significant area requiring the use of management estimates relates to the determination of useful lives for depreciation and amortization. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. The natural gas transmission and distribution operations are conducted through BC Gas Utility Ltd. ("the Utility"). Through Trans Mountain Pipe Line Company Ltd. ("Trans Mountain"), the Company owns and operates a common carrier pipeline system for the transportation of crude and refined petroleum products and, prior to August 16, 1996 (see note 9(a)), also carried out oil and gas exploration and production activities.

Trans Mountain owns 10.5% (1996 – 10.0%) of the common shares of the Company. The cost of these shares is shown as a deduction from shareholders' equity.

Through Inland Pacific Enterprises Ltd. ("IPEL"), the Company holds interests in various energy and utility related subsidiaries including an interest in NW Energy (Williams Lake) Limited Partnership ("NW Energy"), which owns and operates a wood waste-fired independent electricity generating power plant. On August 5, 1997, IPEL increased its interest in NW Energy from 66.7% to 100%. The acquisition has been accounted for by the purchase method and the results of operations have been included on a wholly-owned basis commencing on the acquisition date.

REGULATION

The Company's gas utility operations are subject to the regulation of the British Columbia Utilities Commission ("the Commission"). The Company's oil pipeline operations are regulated in Canada by the National Energy Board and, in the United States, tariff matters are regulated by the Federal Energy Regulatory Commission.

These regulatory authorities exercise statutory authority over such matters as rate of return, construction and operation of facilities, accounting practices, and rates and tolls.

INVENTORIES OF GAS IN STORAGE AND SUPPLIES

Inventories of gas in storage and supplies are valued at cost determined mainly on a moving-average basis.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost which includes all direct costs, betterments, an allocation of overhead costs and an allowance for funds used during construction.

Depreciation of regulated assets is provided on a straight-line basis on plant in service at rates approved by regulatory authorities. The cost of depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation.

Depreciation of non-regulated equipment is provided using the declining balance method. Depreciation of the electricity generating power plant is provided over 25 years at a rate that matches the rate at which revenues are recognized pursuant to the Electricity Purchase Agreement (see note 14(a)).

No provision for future removal and site restoration obligations has been accrued for regulated operations as the extent and cost of such obligations are not currently determinable. Management expects that such costs would be recoverable through future rates or tolls.

DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities require or permit to be recovered through future rates. They are amortized over various periods depending on the nature of the charges and include financing costs such as long-term debt issue costs which are amortized over the original lives of the related debt.

Deferred charges not subject to regulation relate to projects which may benefit future periods and will be capitalized on completion or expensed on abandonment of the projects. Amortization is provided on a straight-line basis over periods from 20 to 25 years.

SIGNIFICANT ACCOUNTING POLICIES

GOODWILL AND INTANGIBLE ASSETS

Goodwill and intangible assets represent the excess of the purchase price over the fair value of the net assets acquired. Goodwill is being amortized over 24.5 years and intangible assets over 20.5 years. Management reviews on an ongoing basis the valuation and amortization of goodwill and intangible assets taking into consideration any events and circumstances which might have impaired the net book value. Goodwill and intangible assets are written down when declines in value are considered to be other than temporary based upon expected undiscounted cash flows of the entity to which the goodwill and intangible assets relate.

RATE STABILIZATION ACCOUNTS

The Utility is authorized by the Commission to maintain two rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, principally temperature and cost of gas fluctuations. The gas cost reconciliation account ("GCRA") accumulates unforecasted changes in gas costs and gas cost recoveries. The revenue stabilization adjustment mechanism ("RSAM") accumulates the margin impact of variations in the actual use for residential and commercial customers from forecast use. The balances are amortized as ordered by the Commission.

REVENUES

Revenue from gas sales is recorded by the distribution utilities on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period.

Revenue for the Firm Energy Component from the sale of electricity is recognized as electricity is generated at rates established in the Electricity Purchase Agreement (see note 14(a)).

PENSION PLANS

The cost of pension entitlements earned by employees is determined annually by independent actuaries utilizing the projected benefit method prorated on services. This cost is expensed as services are rendered and reflects management's best estimates of expected plan investment performance, salary growth, future terminations, mortality rates and retirement ages of plan members. Adjustments which result from plan amendments, changes in assumptions and experience gains and losses are amortized over the expected average remaining service life of the employee group covered by the plan.

POST RETIREMENT BENEFITS OTHER THAN PENSIONS

The Company provides certain health care and life insurance benefits to eligible retirees and their dependants. The cost of providing these benefits is expensed as paid which matches the recovery in rates.

INCOME TAXES

The Company's regulated subsidiaries account for income taxes for regulated operations as prescribed by their respective regulatory authorities. This includes following the taxes payable method of accounting for income taxes, accounting for certain assets and the rate stabilization accounts on a net of tax basis and amortizing deferred income taxes as approved by the Commission. Under the taxes payable method, deferred income taxes are not recorded for significant timing differences in reporting revenue and expenses for financial statement purposes and income tax purposes. This method is followed as there is reasonable expectation that all taxes payable in future years will be recoverable from customers at that time.

The Company and its other non-regulated subsidiaries provide for deferred income taxes for all significant timing differences.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Tabular amounts in millions of dollars, except per share amounts

Years ended December 31, 1997 and 1996

1. PROPERTY, PLANT AND EQUIPMENT

1997	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% - 10%	\$2,204.6	\$ 439.6	\$1,765.0
Plant, buildings and equipment	1% - 33%	263.0	96.3	166.7
Electricity generating power plant	4.2%	123.1	21.2	101.9
Land and land rights	0% - 5%	83.5	1.0	82.5
		\$2,674.2	\$ 558.1	\$2,116.1

1996	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% - 10%	\$ 2,102.8	\$ 395.8	\$1,707.0
Plant, buildings and equipment	1% - 30%	249.7	83.3	166.4
Electricity generating power plant	4.2%	123.1	16.1	107.0
Land and land rights	0% - 5%	83.2	1.0	82.2
		\$2,558.8	\$ 496.2	\$2,062.6

The composite depreciation rate on regulated assets for the year ended December 31, 1997 is approximately 3.0% (1996 - 2.9%).

Included in property, plant and equipment are assets under capital leases with a cost of \$20.2 million (1996 - \$20.7 million) and related accumulated depreciation of \$10.9 million (1996 - \$10.1 million).

2. OTHER ASSETS

	1997	1996
Deferred charges		
Subject to regulation	\$ 23.7	\$ 17.4
Not subject to regulation	14.0	14.2
	37.7	31.6
Goodwill and intangible assets	40.2	8.3
Long-term receivables and investments	5.2	19.4
	\$ 83.1	\$ 59.3

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. LONG-TERM DEBT

	1997	1996
<i>BC Gas Utility Ltd.</i>		
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2000 or September 30, 2015 if extended by holder	\$ 75.0	\$ 75.0
10.30% Series B, due September 30, 2016	200.0	200.0
(b) Debentures:		
9.75% Series D, due December 17, 2006	20.0	20.0
10.55% Series E, due June 8, 1999; 10.75% to June 8, 2009 if extended by holder	60.0	60.0
8.50% Series F, due August 26, 2002	100.0	100.0
7.25% Series G, due July 28, 1998	75.0	75.0
8.15% Series H, due July 28, 2003	50.0	50.0
(c) Medium Term Note Debentures and Medium Term Notes:		
8.80% Series 5, due October 14, 1999	55.0	55.0
9.80% Series 6, due February 9, 2005	40.0	40.0
6.20% Series 9, due June 2, 2008	55.0	—
Various series, weighted average interest rate of 7.48% (1996 – 7.50%) with maturities ranging from 1998 to 2005 (1996 – 1997 to 2005)	41.0	46.3
(d) Preference Shares:		
7.10% Cumulative Redeemable Retractable First Preference Shares	75.0	75.0
Obligations under capital leases, weighted average interest rate of 5.73% (1996 – 7.37%)	9.3	10.6
	855.3	806.9
<i>Trans Mountain Pipe Line Company Ltd.</i>		
(e) Debentures:		
9.75% Series A, due February 18, 2002	44.9	44.9
10.75% Series B, due November 22, 2004	30.0	30.0
11.50% Series C, due June 20, 2010	35.0	35.0
	109.9	109.9
<i>NW Energy (Williams Lake) Limited Partnership</i>		
(f) 11.39% credit agreement, repayable in blended monthly payments, maturing June 1, 2013	124.7	127.5
Agreements payable, non-interest bearing	0.2	0.5
	124.9	128.0
Total long-term debt	1,090.1	1,044.8
Less current portion of long-term debt	96.8	10.9
	\$ 993.3	\$1,033.9

(a) Purchase Money Mortgages

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Utility's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to \$425 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(b) BC Gas Utility Debentures

The BC Gas Utility debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(c) Medium Term Note Debentures and Medium Term Notes

The Utility's Medium Term Note Debenture Program established in 1993 and renewed in 1995 and 1997 allows for the issuance of up to \$400 million aggregate principal amount of debentures during the two year period ending November 26, 1999. Issued debentures are unsecured obligations but are subject to the terms of the Trust Indenture dated November 1, 1977 (see note 3(b)). At December 31, 1997 and 1996, \$8.2 million of Medium Term Notes issued under a predecessor program are not subject to the Trust Indenture.

(d) Preference Shares

These preference shares are redeemable at the option of the Utility on or after September 30, 1999 and are retractable at the option of the holder on September 30, 1999, at \$25 per share plus accrued and unpaid dividends.

(e) Trans Mountain Debentures

The Trans Mountain debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated February 18, 1987, as amended and supplemented.

(f) NW Energy Credit Agreement

The NW Energy credit agreement is secured by a first fixed and specific charge, a floating charge and a security interest over all assets of NW Energy owned and to be acquired and by a \$150 million debenture. The credit agreement contains a number of covenants including maintenance of working capital of NW Energy above \$2.1 million and a provision that no distributions be made to partners if the debt service coverage ratio falls below 1.25.

The Utility's Series B Purchase Money Mortgages and Series F and Series H Debentures and Trans Mountain's Series B and Series C Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

1998	\$ 96.8
1999	194.9
2000	80.2
2001	25.7
2002	151.2

4. NON-CONTROLLING INTEREST

(a) Non-controlling interest in the consolidated statements of financial position	1997	1996
6.32% cumulative redeemable first preference shares of the Utility, 3,000,000 shares issued	\$ 75.0	\$ 75.0
NW Energy (note 9)	-	0.4
	\$ 75.0	\$ 75.4

6.32% Cumulative Redeemable First Preference Shares

These shares are redeemable at the option of the Utility at \$25 per share on or after October 31, 2000, and are exchangeable at the option of the Utility on or after October 31, 2000 for common shares of the Company at a price equal to the greater of \$3 and 95% of the weighted average trading price of the common shares at that time.

The shares are exchangeable at the option of the holder on or after January 31, 2001 for common shares of the Company at a price equal to the greater of \$3 and 95% of the weighted average trading price of the common shares at that time, subject to the right of the Utility to redeem the shares for cash or to find substitute purchasers for the preference shares.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

<i>(b) Non-controlling interest in the consolidated statements of earnings</i>	1997	1996
Dividends on 6.32% preference shares of the Utility	\$ 4.7	\$ 4.7
Recovery of Part VI.1 tax resulting from the utilization of prior years' losses	–	(2.0)
NW Energy	1.1	1.2
	<u>\$ 5.8</u>	<u>\$ 3.9</u>

5. CAPITAL STOCK

The Company is authorized to issue 750,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

Changes in the issued and outstanding common shares are as follows:

	1997		1996	
	Number	Amount	Number	Amount
Outstanding, beginning of year	45,857,258	\$ 387.8	46,184,178	\$ 387.5
Issued under:				
Share option plan	29,180	0.4	532,573	7.5
Payroll deduction employee share purchase plan	7,927	0.2	6,007	0.1
Shares repurchased	(2,209,400)	(18.7)	(865,500)	(7.3)
	<u>43,684,965</u>	<u>\$ 369.7</u>	<u>45,857,258</u>	<u>\$ 387.8</u>
Less common shares held by Trans Mountain	<u>4,592,094</u>		<u>4,592,094</u>	
Outstanding, end of year	<u>39,092,871</u>		<u>41,265,164</u>	

Share Option Plan

The Company has a Share Option Plan whereby officers, directors and certain employees may be granted options to purchase a maximum of 4,000,000 unissued common shares with terms up to 10 years. The option exercise price is the closing sale price of the common shares on The Toronto Stock Exchange on the trading day prior to the date the option is granted. The options are exercisable on a cumulative basis at 20% per annum.

The Plan provides an optionee with the right, by notice in writing, to request the Company to purchase from the optionee for cash all or part of the options as specified in the notice at a price equal to the difference between the market price on the day the notice is received by the Company and the exercise price for those options. Upon receipt of notice requesting the Company to purchase the options from the optionee, the Company has the right to override the request and require the optionee to determine whether or not to exercise the option for unissued common shares. Options purchased by the Company are cancelled. During 1997, options to purchase 684,310 (1996 – 103,540) common shares were purchased for \$3.5 million (1996 – \$0.4 million), net of income tax benefits of \$3.0 million (1996 – \$0.3 million), which has been charged to retained earnings.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The outstanding options for common shares at December 31, 1997 are as follows:

Date granted	Common shares	Exercise price	Expiry date
February 1988	7,400	11.500	February 1998
May 1990	7,250	14.250	May 2000
July 1991	82,210	15.750	July 2001
July 1992	89,100	16.375	July 2002
April 1993	207,440	14.875	April 2003
July 1994	176,010	14.125	July 2004
March 1995	425,668	13.875	March 2005
May 1995	5,600	14.625	May 2005
December 1995	50,000	15.375	December 2005
March 1996	6,000	15.000	March 2006
July 1996	17,960	17.150	July 2006
August 1996	3,000	18.000	August 2006
February 1997	65,000	21.200	February 2007
April 1997	10,000	22.300	April 2007
July 1997	17,500	26.200	July 2007
August 1997	68,000	26.100	August 2007
August 1997	3,000	26.650	August 2007
November 1997	60,000	25.650	November 2007
	<u>1,301,138</u>		

Shares Repurchased

In July 1996, the Company approved a normal course issuer bid to repurchase up to 2,300,000 of the Company's common shares at market prices from shareholders that accept the bid over a period of up to 12 months between August 15, 1996 and August 14, 1997. In June 1997, the bid was amended so that up to 4,100,000 common shares can be repurchased, and the expiry date was subsequently extended to August 14, 1998. During 1997, 2,209,400 common shares were repurchased for \$51.9 million (1996 – 865,500 shares for \$16.7 million). In accordance with generally accepted accounting principles, capital stock was reduced by \$18.7 million (1996 – \$7.3 million), contributed surplus by \$6.8 million (1996 – \$4.1 million), and retained earnings by \$26.4 million (1996 – \$5.3 million).

Reserved for Issue

At December 31, 1997, the number of common shares reserved for issue to meet rights outstanding is as follows:

Under exchange indenture for 6.32% preference shares of the Utility	5,500,000
Under share option plan	2,618,173
Under dividend reinvestment and share purchase plan	2,062,576
Under payroll deduction employee share purchase plan	425,783
	<u>10,606,532</u>

6. OTHER OPERATING REVENUE

	1997	1996
Other gas utility operating revenue	\$ 21.4	\$ 18.7
Gas marketing and international consulting revenue	6.0	4.6
Allowance for equity funds used during construction	0.9	0.9
Other	1.2	0.2
	<u>\$ 29.5</u>	<u>\$ 24.4</u>

7. PENSION PLANS

The Company has defined benefit pension plans available for employees. As at December 31, 1997, actuarial projections of employees' compensation levels to the time of retirement indicate that the present value of accrued pension benefits is \$161.1 million (1996 – \$144.7 million), and the market related value of the assets available to provide these benefits is \$164.5 million (1996 – \$145.8 million).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

8. FINANCING COSTS

	1997	1996
Interest and expense on long-term debt	\$ 96.4	\$ 95.7
Other interest	13.9	26.3
Interest capitalized	(0.9)	(0.8)
	109.4	121.2
Dividends on 7.1% preference shares of the Utility	5.3	5.3
	\$ 114.7	\$ 126.5

9. OTHER GAINS AND LOSSES

On August 5, 1997, the Company increased its interest in NW Energy from 66.7% to 100% for cash consideration of \$29 million, which was allocated primarily to intangible assets. Subsequent to the acquisition, the Company incurred \$13.7 million (\$9.3 million or \$0.23 per share after tax) of costs in anticipation of the disposition of its interest in NW Energy. Discussions with British Columbia Hydro and Power Authority ("BC Hydro") relating to certain aspects of the electricity purchase agreement between NW Energy and BC Hydro are continuing but have not been completed. Given this situation, the Company has determined that it is prudent to write off these costs in the year ended December 31, 1997.

Other gains and losses in 1996 of \$36.8 million before tax consist of a \$46.5 million gain on the sale of Inland Gas & Oil Ltd. ("IGOL") and a provision of \$9.7 million to reflect an impairment in value of a subsidiary as described below:

- (a) On August 16, 1996, the Company disposed of its oil and gas exploration and production operations by selling all the shares of its wholly-owned subsidiary IGOL for gross proceeds of \$106.3 million. This resulted in a pre-tax gain of \$46.5 million. The after-tax gain amounted to \$41.0 million after the recognition of income tax benefits resulting from the application of current and prior years' losses.
- (b) During 1996, the Company concluded that the value of the goodwill related to its investment in Inland Pacific Energy Services Corp., a Spokane, Washington-based energy marketing subsidiary was permanently impaired. The Company recorded a provision of \$9.7 million in 1996 to write off the investment. No tax benefit was recorded. The subsidiary was sold on July 31, 1997, resulting in a nominal gain.

10. RESTRICTING COSTS

During 1997, BC Gas Utility recorded a provision of \$9.4 million (\$5.1 million or \$0.13 per share after tax) for severance costs relating to an overall cost cutting program which will be implemented in 1998.

11. INCOME TAXES

(a) Variation in effective income tax rate

Consolidated income taxes vary from the amount that would be computed by applying the federal and British Columbia combined statutory income tax rate of 45.62% (1996 - 45.62%) to earnings before income taxes and non-controlling interest as shown in the following table:

	1997	1996
Earnings before income taxes and non-controlling interest	\$ 106.2	\$ 141.6
Combined statutory income taxes in the Province of British Columbia	\$ 48.4	\$ 64.6
Add (deduct) tax effect of:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(7.2)	(15.7)
Application of prior years' capital and non-capital losses	-	(20.6)
Large Corporations Tax	4.3	4.7
Amortization of deferred income taxes	(2.7)	(3.3)
Losses carried forward	2.1	-
Permanent differences between accounting and taxable income	5.2	3.6
Other	(0.5)	(1.2)
Actual consolidated income taxes	\$ 49.6	\$ 32.1

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(b) Deferred Income Taxes

Accumulated deferred income taxes which have not been recorded in the accounts amount to \$206.0 million at December 31, 1997 (1996 – \$196.1 million).

(c) Income Tax Losses Carried Forward

The Company has non-capital losses carried forward for income tax purposes of \$22.7 million at December 31, 1997 (1996 – \$8.1 million) which are available to reduce taxable income for years up to 2004. Tax benefits on \$9.8 million of such losses carried forward (1996 – \$5.3 million) have not been recorded and will be included in the determination of net earnings and earnings per share in the year in which the losses are utilized.

12. FINANCIAL INSTRUMENTS*(a) Fair Value of Financial Instruments*

The carrying value of cash and short-term investments, accounts receivable, bank indebtedness, short-term notes and accounts payable and accrued liabilities approximates their fair value due to the relatively short period to maturity of the instruments.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 1997, or by using available quoted market prices, is estimated at \$1,347.5 million (1996 – \$1,259.1 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates can not be determined with precision as they are subjective in nature and involve uncertainties and matters of judgement.

(b) Derivative Instruments

The Company uses derivative instruments to hedge its exposures to fluctuations in energy prices, interest rates and foreign currency exchange rates. These instruments are for terms of less than one year.

Natural gas derivatives are used to manage natural gas price risk in the gas utility and gas marketing operations. The majority of the natural gas supply contracts of the gas utility operations have floating prices for gas, rather than fixed prices. On behalf of customers, the Company uses gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of gas purchased and the price of natural gas used for rate making purposes are managed through the regulatory process whereby differences are recorded in a deferral account and passed through to customers in future rates.

The gas marketing operations make natural gas purchase and sale commitments in the normal course of business which create exposure to changes in the price of gas. This exposure is managed through the use of natural gas derivatives.

Within the gas utility operations, interest rate and foreign currency risk is managed mainly through the regulatory process. As at December 31, 1997, \$161 million of short-term borrowings in the gas utility operations were subject to interest rate deferral accounts. Foreign currency risk in the gas utility operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through the regulatory process.

Short-term borrowings in the corporate and oil pipeline operations segments are exposed to interest rate risk. The only material foreign currency risk in those business segments relates to the U.S. portion of Trans Mountain's crude oil pipeline system. The corporate and oil pipeline operations segments manage interest rate and foreign currency exposures through the use of interest rate and foreign currency derivatives.

The following table provides fair value information on the Company's natural gas and interest rate derivative instruments. The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

	1997		1996	
	Asset (liability)		Asset (liability)	
	Carrying value	Fair value	Carrying value	Fair value
Natural gas derivatives	\$ (5.4)	\$ (10.6)	\$ 7.6	\$ 28.6
Interest rates derivatives	\$ (0.2)	\$ (0.3)	\$ (0.2)	\$ (0.8)

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with its established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. SEGMENTED INFORMATION

The Company operates principally in two business segments:

- (a) Gas utility operations, primarily involving the transmission and distribution of natural gas for residential, commercial and large industrial customers in British Columbia; and
- (b) Oil pipeline operations, primarily involving the transportation of crude and refined petroleum products principally for seven major shippers from Alberta to the west coast of British Columbia and Washington state.

The Company operates in related businesses, including independent power production, energy marketing services, international consulting, development of water related infrastructure projects, retail energy services and, prior to August 16, 1996 (see note 9), oil and gas production. Also, the Company operates in the United States. At the present time, these operations are not of sufficient size to be reportable as industry or geographic segments. Corporate activities include general corporate expenses and unallocated interest expense of BC Gas Inc.

1997

	Gas utility operations	Oil pipeline operations	Related businesses	Corporate activities	Total
Revenues	\$ 765.8	\$ 129.1	\$ 39.0	\$ -	\$ 933.9
Operating income	183.4	48.8	14.7	(2.9)	244.0
Other gains and (losses)	-	-	(13.7)	-	(13.7)
Restructuring costs	(9.4)	-	-	-	(9.4)
Net earnings (loss)	45.1	20.4	(10.6)	(4.1)	50.8
Earnings (loss) per common share	1.12	0.51	(0.26)	(0.10)	1.27
Total assets	1,862.8	362.6	161.1	1.6	2,388.1
Capital expenditures	105.4	23.6	1.0	-	130.0
Depreciation and amortization	55.4	15.8	6.7	-	77.9

1996

	Gas utility operations	Oil pipeline operations	Related businesses	Corporate activities	Total
Revenues	\$ 724.3	\$ 132.8	\$ 45.1	\$ (0.8)	\$ 901.4
Operating income	164.1	51.1	18.8	(2.7)	231.3
Other gains and (losses)	-	-	36.8	-	36.8
Net earnings (loss)	59.6	20.5	32.6	(7.1)	105.6
Earnings (loss) per common share	1.43	0.49	0.78	(0.17)	2.53
Total assets	1,878.9	358.6	188.3	1.3	2,427.1
Capital expenditures	113.1	15.0	17.6	-	145.7
Depreciation and amortization	56.2	15.3	6.8	0.1	78.4

14. COMMITMENTS

- (a) NW Energy entered into an Electricity Purchase Agreement to supply a certain amount of electricity to BC Hydro for a term of 25 years commencing on April 2, 1993. The price to be paid by BC Hydro consists of a monthly Firm Energy Component and other monthly components to recover certain operating costs subject to certain maximum amounts which are adjusted for inflation.

BC Hydro has a continuing buyout option to purchase the electricity generating power plant during the term of the agreement at the greater of (i) the fair market value of the plant or (ii) the net present value of the Firm Energy Component which would otherwise be payable over the term of the agreement discounted at 12.54% plus the cost of transferring title of the plant to BC Hydro. In the event BC Hydro exercises its option, an amount which approximates the fair market value of the long-term debt as stipulated in the NW Energy credit agreement plus any accrued or unpaid interest is repayable to the lenders in the event of the sale of the plant.

- (b) The Utility and Trans Mountain have entered into operating leases in respect of their head office and other premises. Minimum payments under these leases are approximately \$6.6 million in each of the next five years and \$38.7 million in aggregate.

SELECTED CONSOLIDATED FINANCIAL STATEMENT INFORMATION – UNAUDITED

Dollar amounts in millions

<i>Years ended December 31</i>	1997	1996	1995	1994	1993
Statements of Earnings					
Operating revenue	\$ 933.9	\$ 901.4	\$ 894.9	\$ 854.0	\$ 794.6
Operating expenses	689.9	670.1	693.9	695.2	635.6
Operating income	244.0	231.3	201.0	158.8	159.0
Other expenses	137.8	89.7	128.2	109.4	93.8
Income taxes	49.6	32.1	22.6	6.0	4.4
Non-controlling interest	5.8	3.9	2.7	7.4	8.3
Net earnings	\$ 50.8	\$ 105.6	\$ 47.5	\$ 36.0	\$ 52.5
Assets					
Current assets	\$ 188.9	\$ 305.2	\$ 234.6	\$ 203.9	\$ 198.0
Property, plant and equipment (net)	2,116.1	2,062.6	2,056.8	1,948.4	1,761.6
Other assets	83.1	59.3	75.9	72.3	76.2
Total assets	\$2,388.1	\$2,427.1	\$2,367.3	\$2,224.6	\$2,035.8
Liabilities and Shareholders' Equity					
Current liabilities	\$ 696.7	\$ 648.2	\$ 673.4	\$ 598.9	\$ 486.9
Long-term debt	993.3	1,033.9	1,003.9	986.5	937.1
Other liabilities	109.9	114.3	120.1	95.2	128.3
Shareholders' equity	588.2	630.7	569.9	544.0	483.5
Total liabilities and shareholders' equity	\$2,388.1	\$2,427.1	\$2,367.3	\$2,224.6	\$2,035.8
Cash Flow Data					
Operating cash flow	\$ 170.6	\$ 166.8	\$ 106.7	\$ 110.9	\$ 115.2
Capital expenditures	\$ 130.0	\$ 145.7	\$ 178.6	\$ 218.3	\$ 175.2

SELECTED OPERATING STATISTICS – UNAUDITED

Dollar amounts in millions

<i>Years ended December 31</i>	1997	1996	1995	1994	1993
Gas Utility Operations					
Revenues					
Residential	\$ 431.1	\$ 405.5	\$ 405.3	\$ 385.4	\$ 349.8
Commercial	246.9	231.3	241.6	230.2	224.0
Small industrial	17.3	14.7	14.5	10.8	4.7
Large industrial and other	19.7	19.4	25.9	39.6	62.8
Total natural gas sales revenue	715.0	670.9	687.3	666.0	641.3
Transportation	28.6	33.9	28.1	23.1	20.5
Other	22.2	19.5	20.1	18.9	16.3
Total natural gas revenue	\$ 765.8	\$ 724.3	\$ 735.5	\$ 708.0	\$ 678.1
Natural gas volumes (<i>billion cubic feet</i>)					
Sales volumes	123.0	129.5	119.4	122.3	130.3
Transportation volumes	52.0	53.0	50.8	46.2	36.5
Total natural gas volumes	175.0	182.5	170.2	168.5	166.8
Customers at year end	732,316	716,421	699,012	680,970	658,261
Oil Pipeline Operations					
Revenues	\$ 129.1	\$ 132.8	\$ 114.0	\$ 105.9	\$ 99.6
Transportation volumes (<i>m³/day</i>)					
Canadian mainline	36,523	39,681	35,554	34,341	33,902
Jet fuel deliveries	3,279	3,358	2,841	2,514	2,257
Total throughput	39,802	43,039	38,395	36,855	36,159
U.S. mainline (<i>included in Canadian mainline</i>)	15,004	16,294	13,293	11,477	9,734
Kilometres of pipelines					
Gas utility operations	35,971	35,335	34,401	32,993	31,905
Oil pipeline operations	1,477	1,477	1,477	1,477	1,477
Employees (<i>consolidated</i>)	1,979	1,965	1,979	1,996	1,987

SELECTED CONSOLIDATED FINANCIAL STATISTICS – UNAUDITED*In millions, except where stated otherwise*

	1997	1996	1995	1994	1993
Return on average shareholders' equity	10.7%	10.3%	8.6%	7.2%	7.8%
Dividend payout ratio	0.77	0.36	0.77	0.96	0.63
Interest coverage ratio	2.13	1.83	1.57	1.45	1.70
Debt/debt plus shareholders' equity	0.71	0.69	0.72	0.72	0.72
Common shares outstanding – weighted average	40.1	41.8	41.0	38.7	35.5
Data Per Common Share					
Earnings before non-recurring items	\$ 1.63	\$ 1.48	\$ 1.18	\$ 0.93	\$ 1.43
Earnings after non-recurring items	\$ 1.27	\$ 2.53	\$ 1.16	\$ 0.93	\$ 1.43
Dividends	\$ 0.975	\$ 0.900	\$ 0.900	\$ 0.900	\$ 0.900
Operating cash flow	\$ 4.25	\$ 3.99	\$ 2.60	\$ 2.87	\$ 3.25
Equity	\$15.05	\$15.28	\$13.70	\$13.44	\$12.96
Market price range – High	\$28.00	\$21.15	\$16.00	\$17.25	\$17.00
– Low	\$20.10	\$15.00	\$13.13	\$13.13	\$13.75
– Close	\$27.80	\$20.30	\$16.00	\$13.50	\$16.63

SELECTED QUARTERLY FINANCIAL DATA – UNAUDITED

<i>In millions, except where stated otherwise</i>	Three months ended				Year ended
1997	March	June	September	December	December
Revenues	\$ 342.9	\$ 168.1	\$ 125.9	\$ 297.0	\$ 933.9
Net earnings (loss)	\$ 69.5	\$ (17.9)	\$ (25.1)	\$ 24.3	\$ 50.8
Data per common share					
Earnings (loss)	\$ 1.69	\$ (0.42)	\$ (0.61)	\$ 0.61	\$ 1.27
Dividends paid	\$ 0.225	\$ 0.250	\$ 0.250	\$ 0.250	\$ 0.975
Common share trading – TSE					
High	\$ 22.20	\$ 26.30	\$ 27.60	\$ 28.00	\$ 28.00
Low	\$ 20.25	\$ 20.10	\$ 23.00	\$ 24.00	\$ 20.10
Close	\$ 21.25	\$ 26.00	\$ 25.05	\$ 27.80	\$ 27.80
Volume	2.1	4.0	3.7	1.9	11.7
Common shares outstanding					
– weighted average	41.1	40.7	40.4	40.1	40.1

1996

Revenues	\$ 323.7	\$ 157.3	\$ 121.5	\$ 298.9	\$ 901.4
Net earnings (loss)	\$ 68.4	\$ (19.0)	\$ 13.1	\$ 43.1	\$ 105.6
Data per common share					
Earnings (loss)	\$ 1.64	\$ (0.46)	\$ 0.31	\$ 1.04	\$ 2.53
Dividends paid	\$ 0.225	\$ 0.225	\$ 0.225	\$ 0.225	\$ 0.90
Common share trading – TSE					
High	\$ 16.25	\$ 16.80	\$ 19.05	\$ 21.15	\$ 21.15
Low	\$ 15.00	\$ 15.40	\$ 16.70	\$ 18.50	\$ 15.00
Close	\$ 15.88	\$ 16.80	\$ 18.55	\$ 20.30	\$ 20.30
Volume	2.4	2.6	3.7	4.2	12.9
Common shares outstanding					
– weighted average	41.7	41.8	41.8	41.8	41.8

BOARD OF DIRECTORS

Charles F. Armstrong ^{1,2}

*Pentticon, British Columbia
Corporate Director*

L.I. (Larry) Bell ^{1,2}

*West Vancouver, British Columbia
President and Chief Executive Officer,
Shato Holdings Ltd.*

Robert G. Brodie ^{1,2}

*Calgary, Alberta
Chairman, WIC Western International
Communications Ltd.*

Thomas A. Buell ^{1,2}

*Delta, British Columbia
Corporate Director*

Brian A. Canfield ^{1,2}

*Coquitlam, British Columbia
Chairman, BC TELECOM Inc.*

Donald A. Carlson ¹

*Edmonton, Alberta
President,
Carlson Development Corporation Ltd.*

Marilyn E. Cassidy ^{1,2}

*Vancouver, British Columbia
Corporate Director*

Ronald L. Cliff, C.M., FCA ^{1,2}

*West Vancouver, British Columbia
Chairman, BC Gas Inc.*

Iain J. Harris ^{1,2}

*Vancouver, British Columbia
Chairman and Chief Executive Officer,
Summit Holdings Ltd.*

Robert E. Kadlec ^{1,2}

*West Vancouver, British Columbia
President Emeritus, BC Gas Inc.
Chairman and Chief Executive Officer,
Bentley Capital Corp.*

C. Francis Murphy ^{1,2}

*Vancouver, British Columbia
Counsel, Farris, Vaughan, Wills & Murphy*

John M. Reid ^{1,2}

*Vancouver, British Columbia
President and Chief Executive Officer,
BC Gas Inc.*

Robert T. Stewart ^{1,2}

*West Vancouver, British Columbia
President, R.T. Stewart & Associates*

David W. Strangway ^{1,2}

*Vancouver, British Columbia
Corporate Director*

¹Director, BC Gas Inc.

²Director, BC Gas Utility Ltd.

COMMITTEES OF THE BOARD

Executive Committee

R.L. Cliff (Chairman),

R.G. Brodie, J.M. Reid and

R.T. Stewart

Exercises all the powers of the Directors (except for certain significant decisions reserved by the Board of Directors) in overseeing the management and direction of the Company during intervals between Board meetings.

Audit Committee

T.A. Buell (Chairman),

B.A. Canfield, I.J. Harris and

R.E. Kadlec

Acts on behalf of the Board in reviewing certain financial information prepared for public distribution and in monitoring internal accounting controls. The Committee is responsible for assuring that the Company's financial statements accurately portray the financial condition of the Company and for providing reasonable assurances that the Company is in compliance with applicable laws and regulations, is conducting its affairs ethically and maintains effective controls. The Committee also recommends the appointment, change or reappointment of auditors.

Corporate Governance Committee

R.T. Stewart (Chairman),

R.G. Brodie, T.A. Buell,

C.F. Murphy and D.W. Strangway

Ensures that an effective and efficient approach to corporate governance is maintained, with the objective of assuring the business and affairs of the Company are carried out in a manner that

will enhance shareholder value.

In consultation with the Chairman of the Board, the Committee is responsible for identifying, evaluating and recommending nominees for the Board of Directors.

Environment and Safety Committee

C.F. Murphy (Chairman),

C.F. Armstrong, D.A. Carlson

and M.E. Cassidy

Reviews and approves corporate environmental policy, evaluates the Company's progress in implementing the policy, reviews relevant data and reports, brings information and recommendations to the attention of the Board as appropriate.

Management Resources Committee

L.I. Bell (Chairman),

B.A. Canfield, M.E. Cassidy,

R.L. Cliff and I.J. Harris

Ensures the Company has a plan for continuity of its officers and an executive compensation plan that is motivational and competitive in order to attract, hold and inspire the performance of Executive Management and other key personnel. The intent of the Committee is to enhance the profitability and growth of the Company through effective succession planning.

OFFICERS**BC GAS INC.**

Ronald L. Cliff, C.M., FCA
Chairman of the Board

John M. Reid
President and Chief Executive Officer

Milton C. Woensdregt
*Senior Vice President, Finance and
Chief Financial Officer and Treasurer*

David M. Masuhara
Vice President and Secretary

Donald C. Fairbairn
Vice President, Business Development

Debra G. Nelson
Assistant Corporate Secretary

BC GAS UTILITY LTD.

Ronald L. Cliff, C.M., FCA
Chairman of the Board

John M. Reid
President and Chief Executive Officer

Patrick D. Lloyd
*Executive Vice President,
Business Enabling Services*

Milton C. Woensdregt
*Senior Vice President, Finance and
Chief Financial Officer and Treasurer*

Randall L. Jespersen
Senior Vice President, Gas Supply

Ronald J. Jupp
*Senior Vice President,
Customer Operations*

Daniel G. Besel
Vice President, Corporate Controllor

Mary E. Bruce
Vice President, Human Resources

C.F. (Fred) Hess
Vice President, Technical Services

David M. Masuhara
*Vice President,
Legal & Regulatory Affairs,
and Secretary*

O.B. (Bruce) Newton
Vice President, Distribution Services

Duncan S. Vickers
*Vice President, Information and
Communications Technology*

Debra G. Nelson
Assistant Corporate Secretary

**TRANS MOUNTAIN PIPE LINE
COMPANY LTD.**

Ronald L. Cliff, C.M., FCA
Chairman

John M. Reid
Vice Chairman

Thomas D. Doyle
President

John L. Fingarson
*Vice President, Secretary and
General Counsel*

Robert D. Vergette
Vice President, Operations

Liisa A. O'Hara
*Vice President, Financial Services
and Regulatory Affairs*

Milton C. Woensdregt
Treasurer

Michael W.P. Boyle
Corporate Solicitor and Assistant Secretary

Chuck K. Sam
Controller & Assistant Treasurer

**INLAND PACIFIC
ENTERPRISES LTD.**

Ronald L. Cliff, C.M., FCA
Chairman

John M. Reid
President

Donald C. Fairbairn
Vice President

Debra G. Nelson
Corporate Secretary

INVESTOR INFORMATION

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held on Friday, April 24, 1998 at 11:00 a.m. in the Robson Ballroom, Robson Square Conference Centre in Vancouver, British Columbia.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Registered holders of the Company's Common shares (except residents of the United States) may elect to reinvest their cash dividends in new Common shares. Participants in the Plan may also make optional cash payments of up to \$20,000 per calendar year to purchase additional Common shares. Optional cash payments must be received by the Registrar and Transfer Agent by the last days of January, April, July and October to be reinvested on the following dividend payment date. There are no brokerage commissions payable on shares purchased pursuant to the Plan. For an information package on the Plan, or to register in the Plan, please contact Shareholder Relations.

EMPLOYEE SHARE PURCHASE PLAN

Employees of BC Gas Utility Ltd. may contribute from 2% to 6% of their earnings through payroll deductions to purchase the Company's Common shares. Shares are purchased at 100% of the market price.

COMMON SHARE DISTRIBUTION

Approximately 99% of the outstanding Common shares are owned by residents of Canada. The following table summarizes the distribution of shares at December 31, 1997.

	<i>Shareholders</i>	<i>Shares</i>
Canada	8,085	43,361,072
USA	130	282,259
Others	30	41,634
Total	8,245	43,684,965

COMMON SHARE OWNERSHIP CONSTRAINTS

In accordance with the statute that privatized the Company, the following constraints on BC Gas Inc. share ownership exist: (i) the total number of voting shares held by any one person or associated persons shall not exceed 10% of the total number of issued and outstanding voting shares; and (ii) non-residents of Canada will not be permitted to hold or beneficially own in the aggregate, directly or indirectly, voting shares to which are attached more than 20% of the total number of voting shares outstanding.

Valuation Day Value (December 22, 1971)
Common Shares¹ \$6.50
February 22, 1994 Closing Price, \$15.50

¹Adjusted for the two-for-one stock split on November 18, 1985.

REGISTRAR AND TRANSFER AGENT

Shareholder accounts, including dividend payments, direct deposit service and the transfer of shares are handled by the Company's registrar and transfer agent:

CIBC Mellon Trust Company
Mall Level, 1177 West Hastings Street
Vancouver, B.C. V6E 2K3
Telephone: (604) 688-4330
Toll Free: 1-800-387-0825

DUPLICATE ANNUAL AND INTERIM REPORTS

To eliminate duplicate mailings of annual and quarterly reports, please contact CIBC Mellon Trust Company.

SHARES LISTED (Symbol: BCG)

The Toronto Stock Exchange
Montreal Exchange
Vancouver Stock Exchange

SCHEDULED DIVIDEND PAYMENT DATES

February 28, 1998
May 31, 1998
August 31, 1998
November 30, 1998

CORPORATE OFFICES

BC Gas Inc. and BC Gas Utility Ltd.
1111 West Georgia Street
Vancouver, B.C. V6E 4M4
Main Telephone: (604) 443-6500

Trans Mountain Pipe Line Company Ltd.

Suite 900-1333 West Broadway
Vancouver, B.C., V6H 4C2
Telephone: (604) 739-5000

Inland Pacific Enterprises Ltd.

Suite 1600-1095 West Pender Street
Vancouver, B.C. V6E 2M6
Telephone: (604) 895-3500

SHAREHOLDER RELATIONS

Inquiries regarding the Company's Dividend Reinvestment and Share Purchase Plan and all other inquiries or comments by shareholders regarding the Company should be directed to:

Debra Nelson
Telephone: (604) 443-6559
Toll Free: 1-800-667-9177
Fax: (604) 443-6904

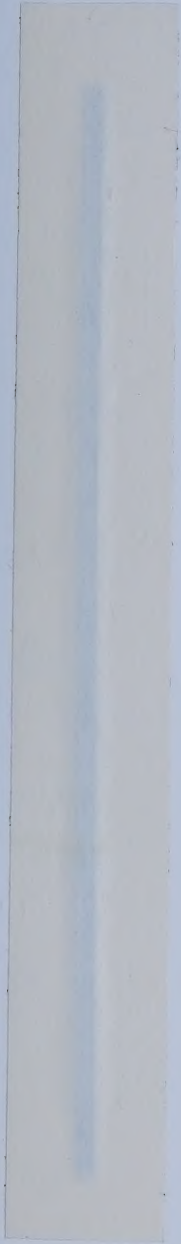
INVESTOR RELATIONS

Portfolio managers, investment analysts and other investors requesting financial information regarding BC Gas should contact:

David Bryson
Telephone: (604) 443-6527
Fax: (604) 443-6929
e-mail: ir@bcgas.com

INTERNET

Web site: www.bcgas.com





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Vancouver, B.C. V6E 4M4